The original documents are located in Box 7, folder: “National Energy Outlook - 1976” of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Chapter VI

FINANCING OUR ENERGY FUTURE

THE CAPITAL SHORTAGE QUESTION

Over the past year there has been concern expressed regarding a possible general capital shortage and, more specifically, the adequacy of capital for the development and conservation of energy. If new investments become increasingly difficult to obtain, critical energy development may be delayed.

Capital formation could be considered inadequate if expenditures exceed the funds made available at reasonably firm interest rates. In theory, there is a rate of return to capital that will provide desired productive capacity under almost any rational circumstances, but that the rate may lead to unacceptably high interest levels. Or, one sector may demand an unusually large share of the market, driving up rates for all borrowers in that sector.

Some recent long-run studies of capital adequacy for the 1975-1985 period have concluded that adequate capital will be available without a major distortion of savings and interest rate patterns. Others suggest that there is substantial risk that capital demands will outstrip supply at reasonable rates by a wide enough margin to cause serious difficulties. A comparison of results and a summary of assumptions for five major efforts are found in Appendix VI-A.

These forecasts differ primarily because of different assumptions made concerning the sources and amounts of investment funds, especially in regard to the probable paths of the following:

- The Federal budget
- State and local budgets
- Monetary policy
- Income and personal savings
- The effects of inflation and tax policy on corporate savings

The two most pessimistic outlooks were published by the New York Stock Exchange (NYSE) and the Chase Econometric Associates, Inc. (Chase). The NYSE study is based on a compilation of pre-recession industry forecasts compared with some projections of savings availability. It concluded that the demand for capital would have exceeded the available supply by as much as $520 billion by 1985. The Chase study is based on projections of massive Federal deficits coupled with stringent monetary policy. Such a combination would produce a new recession before 1980 and would lead to inadequate savings. Meanwhile, the government deficit would continue to drain large sums of money from the available capital pool.

Three relatively optimistic projections were provided by the Department of Labor, Data Resources, Inc. (DRI), and the Brookings Institution. All conclude that there are combinations of Federal economic policy and private savings behavior that can meet the Nation's capital needs.

The Brookings study is the least optimistic; it suggests that a rapid swing to Federal full employment budget surpluses is necessary to avoid problems. The Department of Labor study projects continued Federal deficits, but looks for stimulation of corporate savings and investment through tax measures. The DRI forecast, which forms the economic foundation for this FEA analysis, projects continuing Federal deficits, but also expects a large increase in personal savings. (This study is described in detail in Appendix B.) Financing becomes difficult, however, after 1980, when the economy is expected to be fully recovered from the recent economic slowdown.

After the Nation moves back to a high level of economic activity, increased demand for investment might exceed the supply of available funds. Higher demands for capital might result mainly from prospective increases in environmental, energy, health and safety, and mass transit investment. It is probable that these increases will be offset partly by declines in the need for housing, highways, and possibly, a slower accumulation of inventory.

It appears that a general shortage of capital availability at rates of interest that would fall within recent experience can be avoided, provided national economic policies are sufficiently stable and accommodating. The question then is whether the projected capital demands for energy would increase to an abnormal share. Within the major segments of the energy industry, there may also be areas of excessive requirements in relation to past patterns. Therefore, the aggregate requirements for this industry and the needs for each of the major sectors are examined in detail.

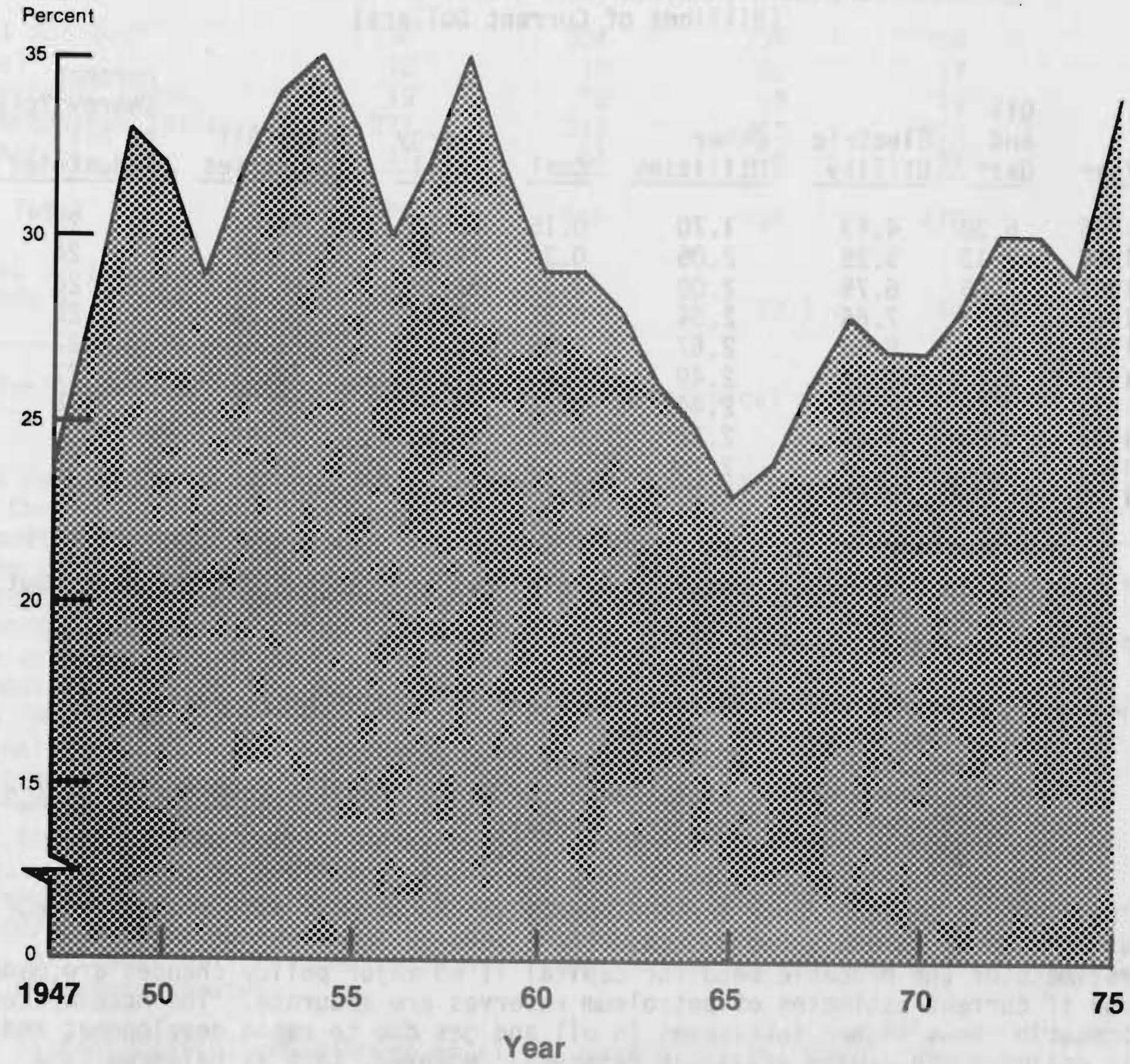
CAPITAL REQUIREMENTS FOR THE ENERGY SECTOR

The magnitude of the energy sector's capital requirements can be evaluated by reviewing the historical share of capital devoted to energy. Future needs usually seem difficult to achieve if the projections are compared only with past dollar expenditures. The problem seems less severe if expanding future energy capital needs are related to the expected growth of the total economic system. Energy's share is best viewed as it relates to new plant and equipment investment.

Energy investments in new plant and equipment have grown from $13 billion in 1965 to $38 billion in 1974 (see Table VI-1). The most significant growth has been in the electric utility sector, which increased more than fourfold in this period. Energy's share of new plant and equipment investment for the total economy has varied around an average of 29 percent during the 1947-74 period (see Figure VI-1). These figures are substantially higher than those accounted for in the Survey of Current Business statistics for the industry,

Figure VI-1

Energy's Annual Share of Business Plant And Equipment Investment



since they include certain oil industry costs such as lease bonus payments, dry hole costs, and some transportation expenditures. The result is a higher percentage of energy investment than that derived in last years Project Independence Report.

Table VI-1

NEW PLANT AND EQUIPMENT EXPENDITURES FOR ENERGY EXTRACTION AND PROCESSING INDUSTRIES
(Billions of Current Dollars)

Year	Oil and Gas*	Electric Utility	Other Utilities	Coal	Energy Total	Total All Industries	Percent Energy Total to All Industries
1965	6.38	4.43	1.70	0.15	12.66	54.42	23
1966	7.13	5.38	2.05	0.39	14.95	63.51	24
1967	7.65	6.75	2.00	0.32	16.72	65.47	26
1968	8.35	7.66	2.54	0.37	18.92	67.76	28
1969	8.18	8.94	2.67	0.38	20.17	75.56	27
1970	8.23	10.65	2.49	0.43	21.80	79.71	27
1971	7.25	12.86	2.44	0.46	23.01	81.21	28
1972	9.05	14.48	2.52	0.63	26.68	88.44	30
1973	10.64	15.94	2.76	0.59	29.93	99.74	30
1974	16.63P	17.63	2.92	0.56	37.74	112.40	34

* Does not include lease rentals or geological and geophysical expenses, but does include lease bonus payments.

P-preliminary

Sources: Electric and Gas data: New Plant and Equipment Expenditures; Survey of Current Business.
Coal data: McGraw-Hill Spending Survey.
Petroleum data: Chase Manhattan Bank, Capital Investments of the World Petroleum Industry, Annual.

The range of capital needs for the energy sector is best illustrated in four of the scenarios evaluated by FEA. The Reference Scenario provides an estimate of the probable need for capital if no major policy changes are made and if current estimates of petroleum reserves are accurate. The Accelerated Scenario shows higher investment in oil and gas due to rapid development and to optimism concerning available reserves. However, this is balanced by a reduction in electric utility spending due to more efficient use of generating plant through a load management program. The Electrification Scenario involves added capital costs needed to meet higher demands for electricity, while the Regulation Scenario shows the capital needs for the oil and gas industry, should price regulation continue (see Table VI-2).

Table VI-2

CUMULATIVE CAPITAL REQUIREMENTS FOR ENERGY
1975 - 1984
(Billions of 1975 Dollars)

	Reference	Accelerated Supply	Electrification	$9 Oil Price Regulation
Oil and Gas*	234	304	234	154
Coal	18	18	22	17
Synthetic Fuels	19	19	19	19
Electric Utilities	277	215	323	257
Other	31	31	36	31
Total	579	587	634	478
Cost of Imports in 1985 at $13/bbl.	27.8	6.8	23.3	44.4

* Excludes lease rentals and geological and geophysical expenses.

The Regulation Scenario results in the lowest capital expenditure total, due to the low level of expenditures by the oil and gas industries. In the face of a domestic limit on the prices, the amount of drilling that is profitable to undertake is limited, and substantially less drilling takes place, with a resulting lower demand for capital than the other strategies. While the capital expenditures are more than $100 billion below those of the Reference Scenario, the expected annual bill for imported oil at $13 per barrel is higher by almost $17 billion in 1985, and imports increase from 5.9 million barrels per day (MMB/D) to about 9.5 MMB/D. Both the Reference and Accelerated Scenarios have capital requirements of between $579 and $587 billion, or about 30 percent of total plant and equipment expenditures expected during the period (near the historical average). However, the pattern of expenditures and the resulting import levels are very different. The Accelerated Scenario requires a very rapid buildup of oil and gas exploration and development expenditures, which is balanced by a reduction in utility spending as load factors improve due to an active load management program. This case shows the oil import bill reduced to $6.8 billion in 1985 against $27.8 billion for the Reference strategy.

The highest capital expenditure of all is needed for the Electrification Scenario which would require $634 billion, or 32 percent of expected plant and equipment expenditures between 1975 and 1984. This percentage is high relative to the past average, but below the level of some of the peak years, including 1974, when energy took 34 percent of the total. In this case, both the oil and gas industry and the electric utilities expand their investments concurrently, and the oil import bill is reduced by $4.5 billion in 1985 from the Reference Scenario level. While this level of demand for capital might not lead to a capital shortage, it might require that both oil and gas prices and electricity prices rise above the projected levels to provide a higher than projected rate of return to attract the additional capital needed.

ENERGY SECTORAL CAPITAL REQUIREMENTS

Even in the cases in which aggregate energy capital demands are within the normal range, there may be individual, sectoral problems. Therefore, each sector was assessed separately to check for the possibility of potential capital problems. Each section compares the expected expenditures of an energy sector against the background of historical behavior, other forecasts, and the available funds within the industry.

Oil and Natural Gas

During the late 1960's, there was relatively little increase in domestic petroleum expenditures for production and exploration. The emphasis during that period shifted to the development of overseas fields from which oil could be delivered to the United States more cheaply than oil from new domestic sources. However, as our imports increased, national policy favored domestic production. Attractive new domestic leases were offered and leasing costs rose rapidly in the early 1970's, followed, with a lag, by other production costs.

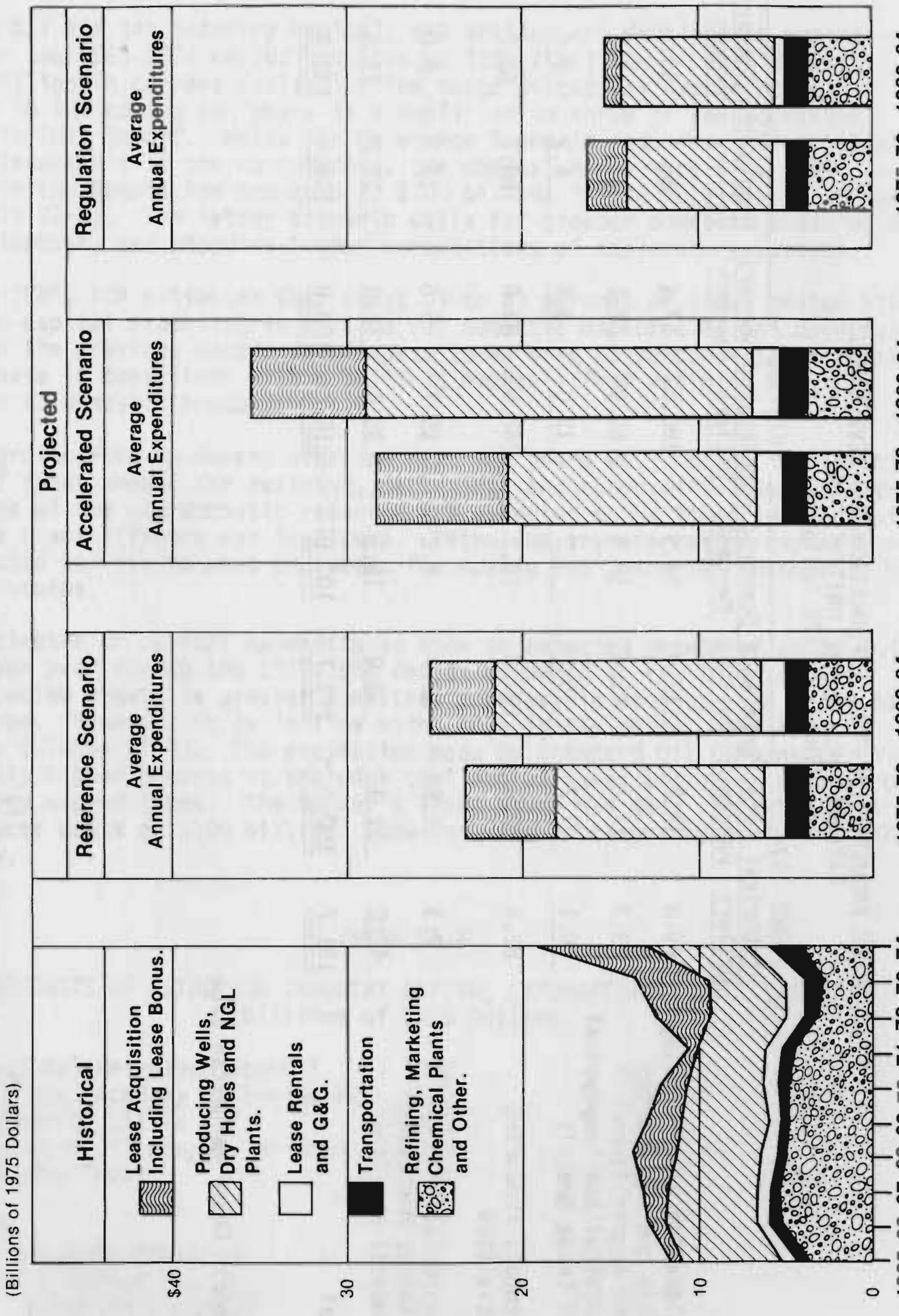
The Arab oil embargo, which began in October 1973, further emphasized the importance of rapidly exploring for and developing domestic reserves, and the recent rise in domestic expenditures is expected to continue throughout the coming decade. Most of the emphasis will be on exploration and production. Over the 1975-84 period total domestic investments in oil and gas exploration, development, marketing, refining, chemical and other activities, are expected to range between $159 and $316 billion, depending on the extent to which new domestic reserves can be discovered and developed (see Figure VI-2).

The capital requirements are derived from estimates of the cost of exploration and development drilling needed to support the projected oil and gas production. For special regions (such as Alaska) which are not estimated by FEA's oil supply model, the cost of production is determined from engineering estimates (see Appendix D for a description of the oil model). Lease bonus costs are derived by assuming that the marginal bidder is prepared to bid enough to make up the difference between its drilling and production cost at the expected finding rate and the marginal price derived in the FEA Project Independence Evaluation System (PIES) equilibrium model. Transportation, marketing, refining and other costs are estimated based on the projected quantity of oil in commerce in 1985. No allowance is made in these estimates for additions to net working capital by the industry. However, historically the companies do not seem to have added large amounts to net working capital except in years of unusually high profits, as in 1973 and 1974.

Figure VI-2

Oil and Gas Industry Capital, Exploration and Development Expenditures in the United States 1965-1984

(Billions of 1975 Dollars)



Source of 1965-1973 Data — Chase Manhattan Bank.

Table VI-3

PETROLEUM INDUSTRY CAPITAL, EXPLORATION AND DEVELOPMENT
EXPENDITURES IN THE UNITED STATES
(Billions of 1975 Dollars)

	1965-1974 Historical Data		1975-1984 Reference Scenario		Accelerated Scenario		Regulation Scenario	
	Dollars	Percent	Dollars	Percent	Dollars	Percent	Dollars	Percent
Exploration and Producing								
Wells and NGL plants	49.0	37.2	137.4	56.4	180.6	57.1	85.3	53.5
Lease Acquisitions	23.3	17.7	45.4	18.6	69.9	22.1	17.7	11.1
Geological and Geophysical and Lease Rentals	10.1	7.7	10.2	4.2	12.0	3.8	5.7	3.6
Subtotal, Producing Activities	82.4	62.6	193.0	79.2	262.5	83.0	108.7	68.2
Transportation	7.3	5.5	12.7	5.2	15.7	5.0	12.7	8.0
Refining, Marketing, Chemical and Other	42.0	31.9	38.0	15.6	38.0	12.0	38.0	23.8
Total	131.7	100.0	243.7	100.0	316.2	100.0	159.4	100.0

Source: Chase Manhattan Bank

Domestic oil and gas industry capital, exploration and development expenditures for the 1965-1974 period amounted to $131.7 billion in 1975 dollars ($96.9 billion in current dollars). The range of capital expenditures expected in the coming ten years is exemplified in three of the scenarios covered in this Report. While the Reference Scenario requires $244 billion of capital investment in the next decade, the capital needs vary from $159 billion in the Regulation Scenario to $316 billion in the Accelerated Scenario (see Table VI-3). The latter scenario calls for greater domestic exploration and development, and embodies higher expectations of exploratory success.

For 1975-1984, FEA estimates that about 70 to 83 percent of total United States petroleum capital expenditures will be for domestic exploration and development. In the previous decade such expenditures were 63 percent of the total. The increase is consistent with a shift in emphasis from refining and marketing to domestic production.

A lower growth rate in demand over the next ten years will reduce the relative amount of funds needed for refining, marketing, and other activities. A large percentage of the new domestic reserves are expected to be found in the capital intensive areas offshore and in Alaska. Petroleum transportation expenditures are expected to rise to meet the needs for moving the resources onshore to the lower 48 states.

These estimates of capital expenditures show an expected growth of up to 9.0 percent per year during the 1975-1984 decade compared to the 1973 levels. This projected growth is greater than that forecast in studies made prior to the Embargo. However, it is in line with, or slightly below, more recent estimates (Table VI-4). The projection made by Standard Oil Company of Ohio is slightly higher because it includes coal expenditures and other non-petroleum energy expenditures. The Banker's Trust study was made since the embargo, and projects costs of $190 billion. However, the costs are based on the 1972 NPC study.

Table VI-4

FORECASTS OF PETROLEUM INDUSTRY CAPITAL EXPENDITURES, 1975-1984
(Billions of 1975 Dollars)

National Petroleum Council	- 1972	$ 160
National Academy of Engineers	- 1974	179
Arthur D. Little	- 1974	146
Standard Oil Company of Ohio	- 1975	281
Bankers Trust	- 1976	190
FEA		
Reference Scenario		244
Accelerated Scenario		316
Regulation Scenario		159

The central question is whether the petroleum industry will have any problem raising required funds. Although expenditures are made regionally, they are financed through worldwide operations of the companies. There is no direct, immediate way to determine the exact sources of funds for domestic U.S. operations.

On a worldwide basis during 1965-1974, investment funds for 30 of the largest companies producing oil and gas in the United States came largely from the rapid write-off of drilling expenses, and from depreciation and depletion. The sum of these items amounted to 49 percent of all net sources of funds, and almost 60 percent of exploratory development and capital expenditures. Earnings retained in the business amounted to 29 percent of total net sources of funds and 35 percent of capital, exploration and development expenditures. Net external financing amounted to only 12 percent of the total net sources and 14 percent of capital, exploration and development expenditures (see Table VI-5).

Table VI-5

SOURCES AND USES OF FUNDS FOR WORLDWIDE OPERATIONS OF GROUP OF THIRTY LARGE PETROLEUM COMPANIES, 1965-1974
($ Billion)

Net Sources of Funds	Dollars		Percent
Net Income	74.8		
Less: Dividends	(33.9)		
Income Retained in the Business		40.9	29.4
Writeoffs and Non-cash Charges		68.2	49.0
Net Funds Generated from Operations		109.1	78.4
Long Term Debt Issued	35.1		
Less: Long Term Debt Repaid	(19.6)		
Net Long Term Debt Issued		15.5	11.1
Preferred and Common Stock Issued	3.2		
Less: Preferred and Common Stock Retired	(2.0)		
Net Stock Issued		1.2	0.9
Sale of Assets and Other		13.4	9.6
Total		$139.2	100.0
Uses of Funds			
Capital, Exploration and Development Expenditures		117.4	84.3
Investments and Advances		6.4	4.6
Increase in Working Capital		15.4	11.1
Total		$139.2	100.0

Source: Chase Manhattan Bank, "Financial Analysis of a Group of Petroleum Companies"

Over the 1965-1974 period, the petroleum industry averaged a return on equity that was slightly above the average for all domestic industry. However, the average masks the significant distortions stemming from the large crude and product price increases of 1973-1974. For the period 1965-1972, petroleum companies averaged an 11.8 percent return on equity against 12.3 percent for all industry. In 1973 and 1974 the petroleum industry return rose to 15.6 and 19.9 percent due mostly to high inventory profits as prices rose dramatically (see Table VI-6). For 1975, the return is estimated to have dropped back to about 13 percent, more in line with that of other industries

Table VI-6

WORLDWIDE RETURN ON EQUITY OF PETROLEUM COMPANIES

	Percent Return on Equity	
	All Industry*	Petroleum
1965	13.8	11.9
1966	14.1	12.6
1967	12.6	12.9
1968	13.2	12.9
1969	12.7	12.1
1970	10.3	10.9
1971	10.9	11.2
1972	12.1	10.8
1973	14.5	15.6
1974	15.3	19.9
Weighted Average		
1965-74	13.0	13.4
1965-72	12.3	11.8

* Excludes transportation companies, public utilities, and financial companies.

Source: First National City Bank (New York)

In recent years, the larger companies have been purchasing a major share of the OCS and Alaskan leases. Since a large proportion of new expenditures will be in these areas it is probable that these companies will bear the major portion of the projected increase in exploration and development expenditures.

Capital, exploration and development expenditures over the 1975-1984 decade are projected to increase in real terms at an annual rate of up to 9 percent versus 1973 levels as compared with an average annual rate of 2 percent from 1965-1973. These expenditures amounted to almost 85 percent of the net changes in the assets of the large oil companies between 1965-1974. The bulk of the remaining 15 percent was an accumulation of working capital during a period of unusually high profits.

Exploration and production expenditures and lease bonuses in the 1975-1984 decade will rise from historical levels of about 60 percent to between 70 and 80 percent. Writeoffs and non-cash charges consist largely of depreciation, depletion, and expensing of dry holes and intangible drilling costs. In the past, these charges have contributed a cash flow equivalent to 60 percent of the capital, exploration and development expenditures.

The increase in the relative importance of exploration and production would indicate that writeoffs and non-cash charges could contribute more than their historical share. However, the Tax Reduction Act of 1975 partially eliminated the percentage depletion allowance and there are a number of bills being considered which might change the tax treatment of intangible drilling expense to require that it be capitalized.

The majors and large integrated companies covered in Table VI-5 account for approximately 70 percent of the crude produced in the United States, and for about 70 to 80 percent of all domestic petroleum industry capital and exploration expenditures. These companies have been the most successful in raising funds internally. The remaining companies have been more dependent on external sources. On balance, it would appear that, for the whole industry, 50 to 60 percent of total capital, exploration and development expenses would probably be covered by writeoffs and non-cash charges over the next ten years unless major accounting changes are mandated by Congress.

The rest of the needed funds will have to be generated largely through the retention of earnings or through external financing. The oil and gas demand projections made in this Report assume that the companies earn an average real 8 percent return on the total capital invested to find and develop reserves. The average return on equity shown in Table VI-6, was 12 percent; this was the nominal return in current dollars with the full effects of inflation included. FEA believes that 8 percent is a good estimate for the inflation adjusted returns on total capital of non-financial corporations. Such a return can be realized, so long as prices are sufficiently free to rise to cover all the expenses, including the return to capital.

If the price is restricted, either by controls or by competing import prices, the quantity of oil found varies. Drilling does not take place unless the expected oil or gas can be sold at a price which would yeild an 8 percent return on the cost of drilling. Regulation restricts the price, and consequently the drilling, and, to an even greater extent, payment for lease bonuses.

Return on equity should be higher than the overall 8 percent on total investment, since interest expense, after tax is normally less than the total return. The industry has usually paid out about 45 percent of earnings as dividends. Profits for the industry in 1975 were probably near $12 billion, and assuming a 45 percent payout and 60 percent of remaining earnings for investment in domestic operations, about $4 billion would be available from this source. Allowing for growth over the next nine years, this would provide $50 to $60 billion for domestic capital, exploration and development expenditures during the 1975-84 period.

For the Accelerated Scenario, then, writeoffs and earnings retained could provide about $240 to $250 billion of the $316 billion required. For the Reference Scenario up to $200 billion could be provided and for the Regulation Scenario $130 to $140. External financing therefore, should range between $30 and $75, with the higher amount most likely in the Accelerated Scenario where the industry is most likely to be able to raise large amounts of funds.

The amount of external financing required falls in a range of 15 to 25 percent of total capital, exploration and development expenditures, versus a rate of about 15 percent in the past for the large companies. The amounts to be raised are large compared with the past, but they appear manageable. The larger amounts to be raised would only be necessary after the discovery of substantial new reserves. Provided adequate pricing flexibility is permitted, the necessary funds should be forthcoming.

All scenarios discussed here except the Regulation Scenario assume decontrolled prices for oil and gas. The Energy Policy and Conservation Act calls for phased decontrol over 40 months. So long as producers can make plans based on decontrolled prices after that period, the results calculated above would be reasonable forecasts. However, there are a number of uncertainties that could reduce the amount of earnings retained and increase the need for external financing or decrease the amount of oil or gas produced:

- further oil price controls could be mandated
- natural gas price controls could be continued
- foreign tax credits could be limited by Congress
- a windfall profits tax could reduce profits below the projected levels
- OPEC countries could impose increased taxes on oil production
- divestiture of some operations of large companies could be mandated

These possibilities could cause the companies to reduce output or to need a greater supply of external funds. Also, the short run pattern of investment increases during the ten years might put relatively more capital stress during the early years as large payments are made for accelerating lease bonuses and exploration.

Some of the needed funds could come from at least two sources not yet discussed. The natural gas transmission companies will probably finance all or part of the Alaskan gas delivery system. In addition, the gas utilities have announced that they expect to invest up to $9 billion over the period to find more gas. The FPC has disallowed one form by which such payments can be made, but many gas companies have gas exploration subsidiaries, and may develop other ways of assuring supply.

Some funds may also come through repatriation of overseas assets, as the emphasis shifts to domestic production. In the short run, these funds may also be augmented by payments made by the OPEC countries for nationalized properties. These nations may themselves seek to invest in the industry they understand best, the oil industry, although there is little evidence to date that they will do so. Some of this money could be spent to finance domestic U. S. operations.

On balance, it would appear that the industry should be able to raise sufficient capital for the needed expansion without significantly departing from its past financial practices. There may be periods of temporary stress in the early years, but provided that there is no further major readjustment in the industry accounting practices and taxation rules, or that, in the long-term, prices are not controlled below the required levels, the needed funds should be available.

Coal Industry

Although the financial requirements of the coal industry are modest in comparison to those of both the electric utility and the oil and gas industries, they are substantial in absolute terms and may require patterns of investment unfamiliar to the industry.

The capital requirements are obtained by summing the capital needed for all mines of a specific type that the FEA forecasts will be opened or expanded. The mines can be either surface or deep. If surface, annual production rates, overburden ratios and seam thickness are significant variables. Deep mines, in turn, can have differing annual production rates, seam thicknesses and gallery depths. Operating and capital costs have been developed for a total of 148 different mine types.

Detailed engineering costs are actually developed for two base case model mines; a one million ton per year deep mine with a six-foot seam 700 feet below the surface, and a one million ton per year surface mine with a six-foot seam and a 10:1 overburden ratio (see Table VI-7). Parametric cost relationships have been developed for the several variables and the costs of the remaining 146 mine types are then developed using these parametric relationships.

During the ten years 1975-1984 it is assumed that 300 million tons of existing capacity are replaced with new mines. The ongoing deferred capital expenditures for both existing and new mines were counted as projected only for that ten year period. An allowance was also made for work in progress on mines to be opened during the years after 1984.

In most of the scenarios coal production in 1985 is near that projected for the Reference Scenario, 1,040 million tons per year. The Electrification Scenario embodies special measures to increase coal production, and therefore has the highest production forecast, at 1,268 million tons. The capital requirements for the industry reflect this production shift, with $17.7 billion needed for the Reference Scenario and $22.4 billion for the Electrification Scenario. A comparable study reported by AMAX Coal indicated

Table VI-7

COSTING SUMMARY OF BASE CASE MINE MODELS

	Underground Mine	Strip Mine
Initial Capital	$30,800,000	$17,700,000
Deferred Capital	11,700,000	3,200,000
Total Capital Investment	$42,500,000	$20,900,000
Annual Production	1,000,000 tons	1,000,000 tons

that capital requirements would range between $15.4 billion and $16.4 billion. A recent study by Bankers Trust Company of New York projects investments of $22.6 billion. In contrast the industry's capital spending was $6.5 billion between 1965 and 1974 (in 1975 dollars).

In order to assess the industry's ability to finance its projected expansion, it is necessary to recognize that at least four different groups of coal mine operators exist and that the financing problems and methods of the four will be different. The four groups of operators are:

- Captive mines -- owned by coal users
- Major diversified national corporations for which coal mining is one of several interests
- Large independents
- Small independents

In terms of coal currently being mined, the industry is dominated by the second group, by the coal-mining subsidiaries of major firms in other industries. Of the 10 largest coal producers in 1974, only two were independents and were ranked fifth and ninth respectively. Of the 15 largest producers, which produced 48.5 percent of all coal mined in 1974, five were independents. The next 35 operators produced an additional 17.5 percent of all coal produced.

The companies owning coal mines tend to have their major interests in minerals or oil. In addition, a number of steel producers and public utilities have large captive coal producers who channel all of their output to the parent company. Consequently, the ability of the coal-producing subsidiary to obtain the requisite capital depends on the ability of the parent company to obtain capital. Neglecting the three captive companies in the top 15, four of the remainder are subsidiaries of large oil companies, three are subsidiaries of mining companies, and the remaining five are the independents.

Since major financing problems for the oil and mining industries are not anticipated, we would not expect difficulties for these coal producers. FEA's analysis assumes that the coal price is sufficiently high to provide a competitive rate of return and to justify its selection among alternatives.

The third group of producers are the large independents. A feature of many in this group is that, often, one half to three quarters, of their production and reserves are in the form of metallurgical coal. The demand for this type of coal is expected to remain strong and the coal companies can be expected to show a preference for developing their metallurgical resources first, in order to obtain the premium prices that such coal commands on both the domestic and export markets. Price increases for all coal over the past two years have improved the profitability of the major independents and they should have little difficulty financing their future expansion.

The same is true of the fourth group, the small independents. This group has traditionally been marked by its financial conservatism which is manifested by low debt to equity ratios and a history of financing from retained earnings. Borrowing by this group has, until recently, been largely confined to short-term bank loans. In recent years, there has been some evidence of a greater willingness by the small producers to assume long-term debt for the financing of new projects and also a greater preparedness by banks to provide this debt.

Over the years, most steam coal has been sold under long-term contracts. Due to the security that such contracts offer both the producer and the consumer it is probable that this practice will continue. The existence of a long-term contract with a stable customer (largely electric utilities) reduces the uncertainties associated with opening new mines and hence the ability to negotiate such contracts makes such mines a more attractive investment for the financial institutions. This feature applies to operators of all sizes.

A significant factor to be considered is that the need to nearly double coal production over the next ten years will require major changes in the current geographic patterns of production. Although considerable new development will be required in Appalachia, much of the new production will come from hitherto undeveloped regions west of the Mississippi. It is by no means clear that the development of these regions will be undertaken by the traditional coal producing companies, most of whose production is now concentrated in the Appalachian region. Certainly, it should not be anticipated that many of the small independents who now form the majority of companies in the coal industry will be involved in the development of western coal.

The companies which own, lease or control coal resources in the West, are largely the current major producers. In addition to those companies, however, two of the three largest reserve owners are railroads which do not now have large coal producing subsidiaries. It is currently the practice of these

railroads to lease their lands to other coal producers for development or to enter into joint ventures with them. Consequently, these reserves are likely to be developed at the same pace as the major producers' reserves.

The distribution of investment follows the geographic distribution of new mines predicted by FEA. Appalachian coal is generally high Btu or metallurgical coal with a calorific value of 24 million Btu per ton and a substantial portion of it is mined in the more capital intensive underground mines. Western coal has a much lower calorific value and is largely stripmined (see Table VI-8).

Table VI-8

NEW COAL MINE REQUIREMENTS 1975-1984
(Millions of Tons Annual Capacity)

	Surface	Deep	Total
East	164	193	357
West	288	9	297
Total	452	202	654

The distribution by capital requirement, however is very different. The eastern mines, both surface and deep require substantially more capital per ton of capacity than do the western surface mines. As a result, while 55 percent of the capacity is added in the East, over 75 percent of the capital is spent there.

Table VI-9

CAPITAL REQUIREMENTS FOR NEW MINES 1975-1984
(Billions of 1975 Dollars)

	Surface	Deep	Total
East	5.9	7.6	13.5
West	3.8	.4	4.2
Total	9.7	8.0	17.7

The Reference Scenario calls for a total of 654 million tons of gross new production capacity by 1985. Capacity expansion plans already announced total 390 million tons through 1983, and it should be stressed that plans for mines to open

* Increase in production over 1974 plus replacement of decline in production from existing mines.

in 1979 and beyond would not yet necessarily have been made. Consequently, the expansions already announced seem consistent with a production estimate of roughly one billion tons/year in 1985.

Electric Utilities

The analyses of the electric utility industry in Chapter V and its Appendix V-B describe in detail a number of factors that will influence the financing of this industry over the coming decade. Due to rapidly rising construction costs, siting difficulties, and the requirements for additional environmental and safety equipment, the cost of generating plants has grown very rapidly over the past ten years. This increase in plant costs has made continued rapid growth increasingly difficult for the Nation's electric utilities.

Furthermore, the financial situation of the companies has deteriorated substantially in the past decade. In recent years, the quality of earnings has been declining because an increasing portion of reported earnings reflect inflows expected from future periods which are not received in cash until later. Return on equity has dropped during a period when inflation has made an increasing return on investment necessary. Interest rates have risen while debt ratios remain high. As a result, interest coverage has dropped close to minimum acceptable levels, making it difficult to raise large amounts of new capital. During 1974, the stress in financial markets highlighted this deterioration but in the past year utility rates have improved, and there has been some recovery from the lows.

There have also been major changes in the expected growth rate for the demand for electricity. In 1974 there was no growth in demand for electric power; in 1975, electric demand grew by 2 percent. Most current studies estimate growth in the next ten years to fall between 5 to 6 percent per year, well below the 7 percent growth that was considered normal prior to 1974. Each percent change in the growth rate, assuming no change in relative growth of peak versus average growth, implies about $60 billion in investment in the next ten years. Until the path of future growth becomes much clearer, there will be an unaccustomed level of uncertainty surrounding both utility expected earnings and capital requirements.

Because of the long lead time in the planning and installation of new generating and transmission equipment, however, industry capacity has continued to increase despite the hiatus in demand growth. By the end of 1975, the industry had about 34 percent reserve capacity above the summer peak -- substantially above the generally accepted 20 percent level. The result has been the announcement of a large number of deferrals in investment plans which have reduced the financial requirement expected of this industry over the next ten years. The potential impact of such deferrals on the availability of electric power has been discussed in Chapter V.

The capital requirements for the utility industry are derived through an explicit modeling of the generating capacity required to meet the 1985 demand forecast in each scenario. The expected load is forecast for each region, and the required generating capacity needed is calculated, based on a mix of

base, intermediate, and peak demand. The normal mix assumes a continued mild deterioration of the system load factor to 0.57 from the current 0.61. The load management mix assumes an improvement to 0.67.

The model subtracts the capacity existing at the end of 1974, adjusted for retirements at the rate of .3 percent of on-line capacity per year. It then seeks to add the combination of new facilities that will minimize the 1985 electricity cost, given the costs of available fuels to each region. The resulting cost of power is fed back to the demand model, a new demand derived, and the system is adjusted until the optimum mix is found.

Transmission and distribution capital is then added, based on the generation increment and the regional geography. The national average amount for these expenditures added is .7 times the cost of new generating plant. The cost of the different generating plants is based on the expected average cost of all plants of a given type to be delivered during the period stated in 1975 dollars. These costs include an adjustment for expected escalation factor of 7.5 percent per year for construction costs which is more than the expected increase in the Consumer Price Index. They also include accumulated allowance for funds used during construction (AFDC).

There are two different cost estimates for each of the major types of plant. The normal estimate assumes that there is no improvement in the current construction approval and scheduling process. A second series of cost estimates assumes that through an active program to streamline the plant delivery system, about 10 percent can be cut from costs of long lead time plants (see Table VI-10).

Table VI-10

COST OF NEW ELECTRICAL GENERATING PLANTS
(1975 Dollars per kWe)

Type	Normal	Improved
Nuclear	550	500
Coal Without Scrubber	380	360
Coal With Scrubber	480	440
Oil Fired Steam	310	310
Simple Cycle Turbine	140	140

The specifics of the conventions used in each scenario are discussed in more detail in Appendix E.

Three possible paths of development for the electric utilities are studied in the different scenarios analyzed in this report. The Reference Scenario reflects the expected growth path in the absence of any major changes in behavior; the Accelerated Scenario illustrates the effects of a load management program and reduced construction costs and the Electrification Scenario shows the results of an active program to replace oil and gas consumption with electricity and of reduced nuclear plant costs. The Accelerated Scenario requires about $62 billion less capital for the industry than the Reference Scenario, while the Electrification Scenario requires about $46 billion more (see Table VI-11). While the Electrification Scenario requires 88,300 megawatts of additional capacity, it also assumes the improved cost schedule for nuclear plants.

Table VI-11

CAPITAL REQUIREMENTS OF THE ELECTRIC UTILITY INDUSTRY
(Billions of 1975 Dollars)

	Reference Scenario	Accelerated Scenario	Electrification Scenario
Nuclear Generation	58.2	52.9	63.0
Other Generation	81.8	51.0	96.8
Transmission and Distribution	98.1	72.7	111.9
Increase in Work in Progress	38.5	38.5	50.9
Total	276.6	215.1	322.6

These forecasts have been compared with others that are available. In the Reference and Electrification Scenarios the FEA capital estimates are higher than those of the FPC, Bankers Trust, and Electrical World (see Table VI-12). Some of the difference can be accounted for by the assumption made in the FEA scenarios that the load factor will continue to decline as it has in the past, from .61 to .57. This assumption adds about 45,000 Mwe of capacity requirement to the total. The Bankers Trust forecasts assume a relatively high growth rate and a greater penetration of the more expensive nuclear plants. The rest appears largely due to the uncertainties associated with forecasting plant costs.

The Accelerated Scenario, on the other hand, assumes that an active load management program can improve the load factor between now and 1985, from .61 to .67. Such a program would encourage utility price structures and load handling practices that shift demand to offpeak periods. The result is a more efficient use of capital equipment, and, hence, less need for future investment. This change reduces expansion needs by almost 95,000 Mwe and substantially reduces capital needs during the period.

Electric utilities will continue to be the most intensive users of the capital markets to finance expenditures. Regulation of this industry has served to maintain a stable and, until recently, declining price for power. This low price has been achieved by requiring the companies to depreciate capital equipment over long periods of time and encouraging the use of large amounts of relatively low cost long-term debt. The result of both policies has been that a relatively small share of new capital is generated internally through retained earnings and depreciation. The recent financial history of the investor-owned utilities is discussed in Appendix B to Chapter V.

Table VI-12

COMPARISON OF ESTIMATES OF THE CAPITAL NEEDS OF ELECTRIC UTILITIES
1975-1985
(Billions of 1975 Dollars)

	Total Capital Requirements	Expected Growth Rate in Electric Demand 1974-1985
FEA - Reference Scenario	$ 277	5.4%
Accelerated Scenario	215	5.3
Electrification Scenario	323	6.4
Electrical World	203	5.7
Bankers Trust	246	6.0
FPC - Moderate Growth	210	5.5-6.5
Low Growth	140	3.0-5.0
High Growth	245	6.6-7.2

Since 1965 earnings retained in the business net of AFDC, which contributes no cash to operations, have declined rapidly. In 1974 investor-owned utility companies actually paid out more in dividends than they received in cash earnings. To some extent, the loss in cash earnings has been made up through the deferral of Federal income taxes. However, this source of cash cannot expand indefinitely; total Federal income taxes paid by utilities in 1974 declined to $563 million. It was assumed, therefore, that over the 1975-1984 period the total internal cash generation would be approximately equal to depreciation and would vary between $54 billion in the Accelerated Scenario and and $64 billion in the Electrification Scenario. Total external financial requirements would therefore range between $160 and $260 billion (see Table VI-13.

Table VI-13

EXTERNAL CAPITAL REQUIREMENTS OF THE ELECTRIC UTILITY INDUSTRY
1975-1984

	Capital Expenditures	Projected Depreciation	External Funds Needed
Reference	277	58	219
Accelerated	215	54	161
Electrification	323	64	259

For the past five years long-term external financing by electric utilities has ranged between $8.7 and $13.3 billion with an average of $10.6 billion. Short-term financing has averaged $750 million. In addition to funds needed to finance plant investment, the companies will also need to refinance $11.9 billion of debt that will mature prior to 1985. Most ot this debt can be expected to be refunded by new debt. It is clear that a substantial increase in external financing will be required over the next ten years, even given an active load management program and lower growth than in the past.

Approximately 20 percent of the electric utility sector consists of government-owned facilities, varying from large Federal hydroelectric systems to municipal village power plants. If this ratio of ownership continues into the future, about $30 to $50 billion of the needed financing will be raised by the Federal, State and local government sector. This leaves a range of $140 to $220 billion to be raised by investor-owned utilities.

From 1970-1974, external financing, including short-term debt, of electric utilities averaged 19.5 percent of the total external financing by non-financial corporations. For the period 1975-1984, this total is projected to be $1,232 billion. The projected share ranges from 11 to 18 percent.

However, financing has not always been easy for the industry during the past five years. Starting with 1970 the amount of external financing jumped from the range of $4 to $5 billion up to $8 billion and has risen since to as high as $15 billion. During 1974 there was considerable difficulty in meeting the financial requirements of the industry, and the companies were forced to issue unusually large amounts of short-term debt. At the same time, utility bond ratings were reduced in a period during which low rated bonds were difficult to sell and carried large interest premiums.

Many of these problems have subsided as utility earnings rose and the stock and bond markets recovered. The yield premium on low rated bonds has dropped back to 246 basis points between a Baa utility bond and an Aaa bond. The ratio of the market price of utility common stocks to book value now is .95, up from a low of .67 in 1974. The rate of return on equity has risen from 10.7 percent to 11.5 percent. Total long-term financing in 1975 reached $13.3 billion up from $12.2 billion in 1974, while short-term financing dropped from $2.8 billion to net repayments of $700 million.

The industry still faces many of the problems that became evident in 1974, however, and periods of tightness in capital markets are likely to prove difficult. While interest coverage ratios have improved in 1975, the amount of debt that can be offered remains limited and substantial amounts of equity will be required over the coming ten years. However, if rates are maintained at levels that will allow for a return on equity that is sufficient to maintain the market value of utility common stocks near their book values, the industry will probably be able to raise the needed funds. However, even though the aggregate industry picture looks reasonably sanquine, there are a number of individual companies that face very difficult problems in financing continued growth.

Synthetic Fuels

The United States now supplies about 75 percent of its primary energy from crude oil and natural gas. With domestic reserves of oil and gas dwindling, the Nation has been forced to rely more on imports of these fuels. Since the Nation has taken a strong position in favor of reducing our reliance on imported oil, one of the major alternatives available is to develop a new industry that will make synthetic fuels (oil and gas) from abundant indigenous resources of coal and oil shale.

Although both the Federal Government and energy companies have had R&D programs in synthetic fuels, there was little financial incentive to expand these programs while oil and natural gas prices were low, and far below the estimates for synthetic fuel costs. With the recent rise of world oil prices and with U.S. dependence on imports growing, the attractiveness of developing a synthetic fuels industry is becoming increasingly clear.

Discussions with energy industry and financial executives, as well as testimony in recent hearings before Congress, indicate that no commercial synthetic fuels plants will be built in the United States in the absence of Federal financial assistance. The major obstacles to financing such plants are as follows:

- The funds required for a single plant are frequently too large ($.5 to $1.0 billion) in relation to the assets of companies which are in a position to build and operate it. The cost of construction and operation of the plants is still too uncertain for the companies to risk such large sums.
- No commercial size synthetic fuels plants have been built in the United States. Until the first commercial plants have been built and operated successfully, investors are reluctant to commit funds since they have other investment opportunities of equal or better rates of return involving less risk.
- With construction costs high in relation to plant capacity, the synthetic fuels must sell at high prices (roughly, $12 to $30 per barrel of oil equivalent) in order to yield an acceptable return on investment. There is no guarantee that world oil prices will be that high, and investors need some protection against lower world oil prices.

Therefore, to accelerate the production of synthetics, it appears that the Federal Government would have to provide financial incentives to attract investors. A number of incentive programs have been proposed and assuming that some are instituted, the cost of a large scale synthetic fuels commercialization program would be $19 to $22 billion by the end of 1984. Such a program would provide fuels equivalent to up to one million barrels a day of oil in 1985.

Other

There are a number of other necessary energy expenditures that do not fit readily into the supply categories already covered. The important elements not included are:

- Coal transportation
- Nuclear fuel cycle
- Gas utilities

The discussion of the capital requirements of the coal industry covered only the needs of the mining companies for plant and equipment for the opening and operating of mines. There will also be needs for capital to transport the coal, particularly as the emphasis shifts to the West.

In 1974 about 65 percent of all coal mined was shipped by rail. Coal revenues constituted about 11 percent of total rail freight revenues in that year. By 1985 coal production is expected to rise by 72 percent, with a corresponding increase in the need for rail shipments.

It is estimated that about 300,000 new hopper cars will be needed to meet expansion and replacement needs. At an average cost of $25,000 apiece, this would cost about $7.5 billion over the next ten years. An additional $5.0 billion is expected to be necessary for roadbed and locomotives.

The Electrification Scenario calls for a substantially greater increase in coal production than the other strategies, and, consequently, for higher expenditures for the railroads. In this scenario such expenditures might be as high as $15 billion.

During the period through 1985, one or more slurry pipelines may also be built. These can be expected to replace some of the expenditures that would otherwise be made by railroads, and could serve, in the short run, to increase total expenditures slightly. However, the net change would not appear to be sufficient to change the overall capital picture for coal transportation. There are also other expenditures by the railroads that would be needed, but that do not relate directly and exclusively to coal transportation. These will not be considered as energy related in this Report.

There could be some problems in financing these expenditures in that they are large in terms of the expected expenditures for the railroads, and, on average, the railroad industry is not in a position to take on extensive, new capital requirements. In this case, however, the major rail lines affected are generally among the stronger ones, and a number of consuming corporations are prepared to aid in the financing in order to assure delivery. There will undoubtedly be some problems in raising the needed funds in specific instances, but there should be room to raise the bulk of the funds without severe distortions.

The nuclear fuel cycle is discussed in detail in Chapter V, Appendix A. The discussion indicates that a number of capital projects will have to be undertaken during the next 10 to 15 years to support the developing needs of nuclear powerplants. The requirements for individual plants are covered in the capital needs for the electric utilities, but there are a number of general services needed to support the individual plants. The total capital needs for these services are expected to be $7.3 billion by 1985 (see Table VI-14).

Table VI-14

NUCLEAR FUEL CYCLE CAPITAL REQUIREMENTS, 1975-1984
(Billions of 1975 Dollars)

Use	Capital
Mining	1.7
Milling	1.1
Enrichment	3.6
Fabrication	.3
Waste Management	.6
Total	7.3

The largest part of the expenditure will be for additional enrichment capacity. This may be financed by the Federal Government, or by private industry, but in either case it will be done through special project financing arrangements. It would compete in the corporate financial pool for other funds, but not draw directly from funds for other energy projects, except to the extent that some of the companies involved opt for this project versus choosing another.

The other capital projects either will be financed directly by the Federal Government, or will depend to some extent on policy assurances that an adequate market for nuclear fuels will continue to exist over the life of the investments.

One other major energy sector remains, the gas utilities. During the five years 1970-1974, capital expenditures for transmission, distribution and storage of natural gas averaged $2.2 billion per year. However, proven reserves of natural gas have been declining since 1967, with a resulting decline in production since 1971. The result, in the short run, has been curtailments of service. In the long run this should lead to a redeployment of the industry's investment decisions.

The major emphasis for the next ten years will be on production of natural or synthetic gas to supply existing customers and to permit at least a minimum continued expansion. The companies have projected a total of $28.2 billion for projects relating to the production or delivery of natural gas or high Btu synthetic gas. A large percentage of these expenditures have already been counted as cost of exploration and transportation of natural gas in the oil and gas sector or in the needs for synthetic fuel programs. The domestic facilities for LNG delivery, however, will require $3.6 billion that is not accounted for elsewhere (see Table V-15).

Table VI-15

GAS UTILITY PRODUCTION EXPENDITURES, 1975-1984
(Billions of 1975 Dollars)

	Amount	Not Counted Elsewhere
Exploration and Development	9.2	-
Foreign LNG Imports	3.6	3.6
Pipeline Gas From Coal	7.0	-
Alaskan Gas Delivery System	9.0	-
	28.8	3.6

In addition, there will be some expenditures made to expand or maintain the existing natural gas delivery system. Although reliable estimates are difficult in the face of the current supply uncertainty, it would appear that $5 to $10 billion would be a reasonable estimate for this purpose in the next ten years.

Provided that there is reasonable assurance of a marketable gas supply, this industry should be able to raise the capital needed. The independent companies have not experienced the same level of financial difficulties as the electric utility companies. They have not been faced with the same acceleration in capital expenditures, and have not needed to seek such massive amounts of funds in the financial markets.

ENERGY CONSERVATION

In addition to the capital requirements for energy supply options, there will also be a need for investment capital to foster energy conservation. Measuring such expenditures is far more difficult than those for supply. It is clear that higher energy costs may encourage early replacement of an energy intensive machine or process, but it is less clear which part of the cost of the new equipment is an investment in conservation. There is also the problem of identifying the conservation investment for such purchases as lighter, cheaper cars that use less gasoline.

To provide a preliminary estimate of the amount of capital that might be devoted to conservation, it is assumed that any investment in energy conservation is not likely to be greater than the net present value of the energy savings stream generated by that investment. It is reasonable to assume that this investment will be some fraction of the net present value of the energy savings as some savings are possible with no capital investment (e.g. through

improvement of auto and plane load factors, setting back thermostats, improved housekeeping, etc.).

Energy savings will result from both ordinary price-induced market responses and the governmental conservation policy initiatives described in Appendix E and Chapter I. These policies may be necessary even if many potential conservation investments are economically attractive, since this is not always apparent to the energy consumer. The benefits to individual consumers and firms from energy conservation may appear to be lower than the benefits to the Nation as a whole. There are many practical difficulties such as imperfect information, the presence of external costs in the production, delivery and final use of energy, first cost bias, collectively large but individually insignificant benefits from many conservation options, and pervasive uncertainties especially about future energy prices. The total annual savings stream, including the projected effects of Federal initiatives, by 1985 is estimated to be about 15.6 quads.

The net present value of energy savings is a function of a number of parameters. These include the rate of discount, the price of energy payable by each consuming sector, the useful life of energy saving equipment, and the fraction of energy savings which requires capital investment. The delivered sales-weighted average energy price in 1985 is expected to be $3.75 per million Btu (or about $21.75/barrel) in 1975 dollars. A real discount rate was assumed to be 8 percent per year. The fraction of savings requiring capital equipment was estimated to range between 40 and 80 percent.

Based on alternative assumptions, three cases reflecting high, low and intermediate levels of capital requirements were constructed. The cumulative capital investment needs thru 1985 range from a low of $164 billion to a high of $327 billion with the intermediate estimate of $242 billion.

The industrial savings are approximately equal to the household savings although energy use is 50 percent higher in the industrial sector. The wholesale cost of energy to industry is substantially lower than the retail price of energy to households. Therefore, the household sector has the greater economic incentive to savings.

This analysis provides a rough estimate of the range of possible capital needs for conservation over the next ten years. To judge whether special difficulties are likely to emerge in some major sector of the economy, the level of conservation investment can be compared with the total forecasted investment over the next ten years for the major sectors. A comparison suggests that the overall conservation investment needs are in a reasonable proportion to the aggregate investment and are therefore unlikely to present special financing difficulties (see Table VI-16).

Table VI-16

COMPARISON OF CUMULATIVE CAPITAL REQUIREMENTS FOR ENERGY CONSERVATION THRU 1984 WITH TOTAL EXPECTED INVESTMENT
(Billions of 1975 Dollars)

	Low	Medium	High	Total Expected Investment
Industrial, Commercial and Transportation Except Autos	$ 87	$ 120	$ 169	$ 2,050
Residential Including Autos	77	122	158	$ 2,660
Total Capital	$ 164	$ 242	$ 327	

Source: DRI's Control Long 5/75 forecast for gross private domestic fixed investment excluding residential construction, and for residential construction and consumer durables (See Appendix B).

The indirect approach used here can be only a first step in viewing the costs and benefits involved in conservation. However, it does show that there are potential capital costs, both in adapting to price changes, and in encouraging accelerated energy conservation behavior. The overall capital needs are of about the same magnitude as those of the electric utility or oil and gas industry, but they are spread over the whole economy and are therefore less of a problem to finance. It is difficult to say whether, in the aggregate, investment in energy conservation will be constrained by capital availability. Nevertheless, it can be expected that some part of this investment might replace some financially less attractive investments. These capital costs might also substitute to some degree for capital needed to produce more energy.

APPENDIX VI-A

COMPARISON OF CAPITAL STUDIES*

Table VIA-1

Comparison of Results of Capital Requirements Studies
(percent)

	History	NYSE	BDC	DRI			Labor			Chase		
Years	1965-74	1974-85	1973-80	1975-85	1975-80	1980-85	1975-85	1975-80	1980-85	1975-84	1975-80	1980-84
GNP growth rate	8.2	8.6	9.2	9.4	10.5	8.3	10.0	11.8	8.2	10.0	10.3	9.7
Inflation growth rate	4.8	5.0	4.7	4.6	4.7	4.6	4.8	5.0	4.4	6.2	7.0	5.3
Real GNP growth rate	3.2	3.6	4.3	4.5	5.5	3.6	5.0	6.5	3.6	3.6	3.1	4.1
Unemployment rate	4.6	n.a.	4.3[a]	6.2	7.3	5.0	5.4	6.4	4.3	8.2	8.9	7.8
High-grade (Aaa) corporate bond rate, new issues	6.7	n.a.	7.5[a]	8.6	8.4	8.9	n.a.	n.a.	n.a.	9.9	10.5	9.2
Years	1965-74	1974-85	1973-80	1976-85	1976-80	1981-85	1976-85	1976-80	1981-85	1975-84	1975-80	1980-84
					As percent of GNP							
Gross private domestic investment	15.1	16.4	15.6	15.3	14.7	15.7	15.4	15.4	15.4	14.5	13.9	15.0
Nonresidential	10.4	9.4[b]	10.9	10.6	10.1	10.9	11.2	11.1	11.2	10.6	10.4	10.8
Inventory	1.0	3.1[c]	0.7	0.7	0.6	0.8	0.9	1.1	0.8	0.7	0.5	0.9
Residential	3.7	4.0	4.0	4.0	4.1	4.0	3.3	3.2	3.4	3.1	2.9	3.3
Total savings	15.1	15.0	15.6	15.3	14.7	15.7	15.4	15.4	15.4	14.5	13.9	15.0
Business	10.8	10.6	10.6	11.0	10.9	11.0	11.2	11.3	11.1	10.2	10.2	10.2
Personal	5.0	4.0	4.6	5.4	5.6	5.2	4.7	5.0	4.4	6.2	6.2	6.2
Government	-0.5	0.3	0.2	-0.8	-1.7	-0.1	-0.4	-0.8	-0.1	-2.0	-2.6	-1.4
Federal	-0.8	-0.2	0.3	-1.0	-1.9	-0.4	-0.7	-1.1	-0.5	-2.1	-2.8	-1.4
State and local	0.3	0.5	-0.3	0.3	0.2	0.3	0.4	0.4	0.4	0.1	0.2	0
Other	-0.2	0	0.1	-0.2	0	-0.3	-0.1	-0.1	0	0.1	0.1	0

*Data abstracted from: Fromm, Gary, "Investment Requirements and Financing: 1975-1985," National Bureau of Economic Research, October, 1975

Note: Results estimated when figures in sources are incomplete or presented in other forms. Detail may not add to totals due to rounding; n.a. - not available. Growth rates are compound annual rates of change

a/ Estimated from incomplete statistics
b/ Includes plant and equipment only
c/ Includes inventories and other business, nonresidential investment

SOURCES:
NYSE - The Capital Needs and Savings Potential of the U.S. Economy; Projections Through 1985 (The New York Stock Exchange, September 1974)
BDC - Barry Bosworth, James S. Duesenberry, and Andrew S. Carron, Capital Needs in the Seventies (Brooking Institution 1975)
DRI - Allen Sinai and Roger E. Brinner, The Capital Shortage: Near-Term Outlook and Long-Term Prospects, Economic Studies Series #8 (Data Resources, Inc., 1975)
Labor - Special Study Group, Unpublished materials partially based on The Structure of the U.S. Economy in 1980 and 1985, BLS Bulletin 1831 (U.S. Department of Labor, 1975)
Chase - Michael K. Evans, Long-Term Forecast: The Next Ten Years, Inflation, Recession, and Capital Shortage (Chase Econometric Associates, Inc., August 1975)

Table VIA-2

Summary of Assumptions, Results, and Policy Recommendations in Studies of Capital Adequacy

Study	Federal Government Expenditures	Tax Policy	Federal Budget Position	Monetary Policy	Results	Recommendations
New York Stock Exchange	Projects deficit only	Assumes no change	$3.5 billion annual deficit (based on average deficit 1954-63)	No mention	Savings level inadequate to meet investment demand by $520 billion 1974-85	1. Reduce Federal expenditures 2. Lower corporate income tax rates 3. Reduce capital gains taxes 4. End double taxation of dividends 5. Allow replacement costs depreciation 6. Higher and permanent investment tax credit 7. Repeal withholding tax on income from foreign held securities
The Brookings Institution	1. No net new Federal programs 2. Expenditures grow 8.7% per year 3. Grants-in-aid grow 6.2% per year for continuation of existing programs 4. Transfer payments increase 10.9% per year for funding existing laws	No change; revenues rise 11.1% per year (higher inflation rate would increase revenue growth; tax elasticity - 1.2)	$82 billion initial surplus 1980; used to offset state and local financing gap of $25 billion and increase federal purchases $44 billion. Net surplus--$13 billion. (Note: offsets not included in first column)	Because of fiscal restraint (surplus) easier monetary policy, lower interest rates than 1974	Financing capital needs not "unmanageable." Further shifts to debt financing	Significant shift toward larger government budget surpluses and easier monetary policy
DRI	1. Expenditures grow at 7.0% per year and fall in relation to GNP in real or nominal terms 2. Transfers increase according to law	1. 1975 personal tax cut continued to maintain real tax effect ($12 billion, 1975) 2. Personal tax reduction - $20 billion in 1979, $10 billion in 1984 3. Investment tax credit made permanent	Declining deficits falling, as a percent of GNP, from 3.6 in 1976 to 2.3 in 1977, to 0.4 in 1984-85; levels are $30-40 billion in 1977-79 and $10-15 billion in 1980's	1. Stable, largely accommodating 2. Annual rates of nonborrowed reserves range between 7 and 10%; M1 grows at 5 to 8.5% per year 3. Mild credit squeezes in selected years not counteracted	1. Shortages of physical capacity not likely 2. Financing of capital outlays is relatively easy until 1980 with slight tightness in 1976-77 3. Financing becomes more difficult after 1980, especially 1981 and 1984 4. Ratios of short-term to long-term liabilities and debt-equity rise, causing some cutbacks in investment	1. Expenditure restraint 2. Some business and personal tax cuts 3. Stable and slightly restrictive monetary and fiscal policies; stop-go countercyclical policies create capital shortage and should be avoided

Table VIA-2 (continued)

Study	Federal Government Expenditures	Tax Policy	Federal Budget Position	Monetary Policy	Results	Recommendations
Labor	1. No new programs 2. Growth in transfer payments to reflect real income maintenance 3. Grants-in-aid increase less rapidly than recent past (3.5% real growth)	1. 1975 personal tax cut ($8 billion) made permanent 2. $6 billion personal tax cut in 1976 3. $6 billion/yr in personal tax cuts 1977-82 to maintain real tax effect 4. Permanent 10-11% Investment Tax Credit 5. Corporate profit tax rate lowered to 45% 6. Depreciations allowances increased by 5% 7. Gas tax increase to 7¢/gallon from 4¢	Declining deficit to $8.9 billion, 1985	Accommodating, stable	Adequate funds for investment; 4-5% unemployment. Further shift in balance sheet structure as between debt and equity toward higher debt proportions	General solutions preferred to those which are directed at specific areas of capital shortage
Chase	1. Social Security cost-of-living adjustment cut by $5 billion, 1977 2. No real increase in defense outlays, nominal growth rate 8%; nondefense growth 2.6% real, 10.6% nominal, 1975-84	1. Social Security tax base and rate from $15,200 to $19,500 and from 5.85% to 6.85%, 1977 adds $20 billion revenue 2. Personal income tax rates cut 10% after 1978 recession (1975 Act not renewed beyond 1976) 3. Investment credit raised to average effective rate - 10%, 1979	Deficits: 1976 $63 billion 1977 $33 billion 1978 $47 billion 1979-80 $70 billion 1981-85 declining from $55 billion to $34 billion	1. Unprecedented tight monetary policy, especially in 1978 2. Monetary base growth rate - 7.5% 1975-84	1. Recession in 1978 attributed to monetary policy 2. Investment curtailed by lack of internal funds, high borrowing costs	1. Easier monetary policy 2. Do not raise social security taxes or cut benefits 3. Raise business rate of return and cash flow by: a. Decrease corporate income tax rate to 40% b. Base depreciation allowances on replacement cost c. Integrate corporate and individual taxes remove double taxation of dividends d. Increase investment tax credit