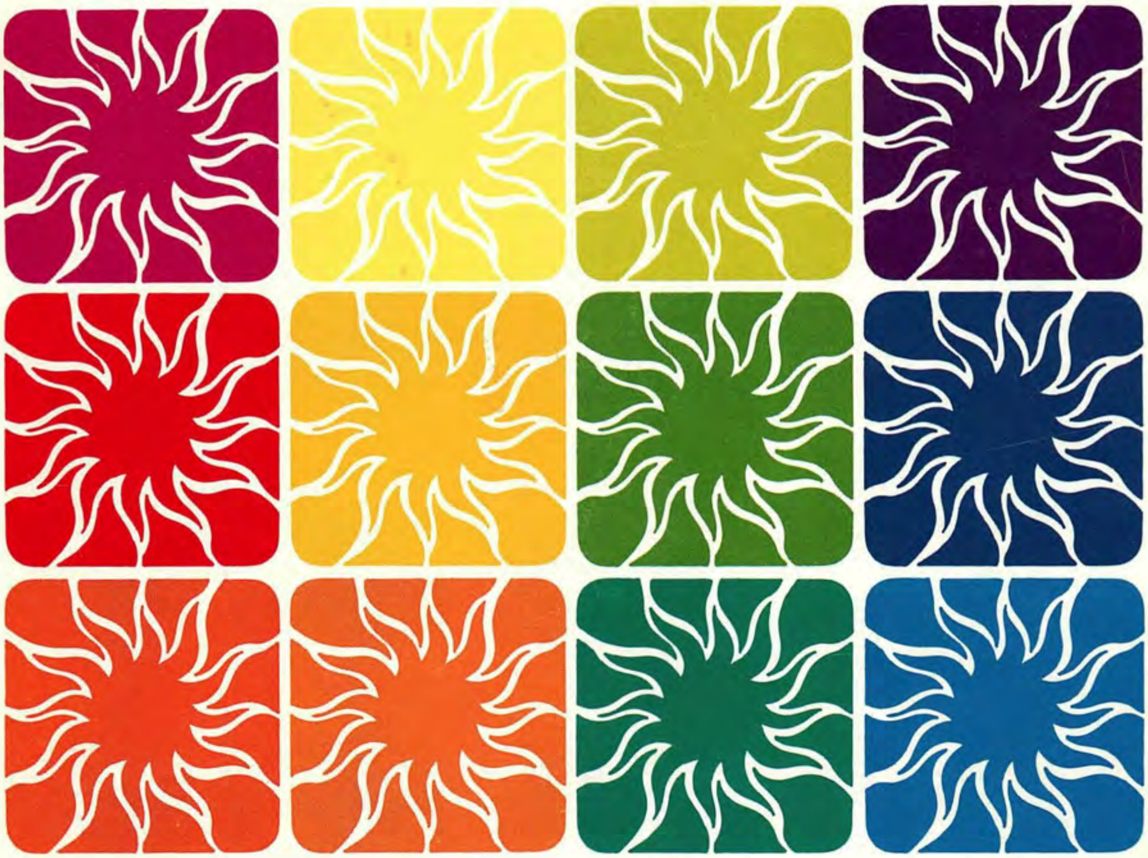

U.S. Energy Outlook

A Summary Report of the National Petroleum Council

December 1972

National Petroleum Council
(Established by the Secretary of the Interior)

December 11, 1972

My dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the NPC report, *U.S. Energy Outlook—A Summary*, approved by the Council at its meeting on December 11, 1972. In addition, a preprint version of the full report of the Main Committee is also enclosed. The detailed studies of the various fuel task groups will be transmitted to you upon completion in the first quarter of 1973.

On January 20, 1970, Assistant Secretary of the Interior Hollis M. Dole asked the National Petroleum Council to undertake a comprehensive study of the U.S. energy outlook from now until the end of the century. In response to this request, the NPC Committee on U.S. Energy Outlook was established under the chairmanship of John G. McLean with the assistance of M. A. Wright, Vice Chairman—Oil; Howard Boyd, Vice Chairman—Gas; D. A. McGee, Vice Chairman—Other Energy Resources; and John M. Kelly, Vice Chairman—Government Policies. The Coordinating Subcommittee was chaired by Warren B. Davis.

On July 15, 1971, the Council submitted to you an Interim Report. This Initial Appraisal assumed that 1970 governmental policies and regulations and the economic climate for the energy industries would continue without major changes in the 1971-1985 period. The findings of the Initial Appraisal demonstrated that significant changes in the economic climate and government policies are essential if the present trend toward growing insufficiency of the U.S. fuel supplies is to be substantially altered. The Committee on U.S. Energy Outlook used the findings of the Initial Appraisal as a point of departure for the second phase of the study.

This final stage of the study has been considerably more complex than the Initial Appraisal. A central feature of the approach for this final report involved the identification of the various economic and government policies which affect the energy situation. Changes in these policies were then postulated and, through a series of parametric studies, the effects of the changes on our energy position were estimated.

The Committee also identified those factors which will influence the Nation's long-term energy posture—from 1985 to the end of the century.

Lastly, at your Department's request, the Committee has offered its recommendations for a United States Energy Policy.

The findings and recommendations in this report represent the best judgment of many energy experts. In addition to representatives of the oil and gas industries working on the study, we also had the generous support and input of some 68 experts drawn from the coal, nuclear and electric utility industries, as well as government, who provided a uniquely broad base for the assessments made in this study.

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The political, economic, social and technological factors bearing upon the U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

In considering this report, the reader should be aware of the following points:

1. While the joint nature of oil and gas exploration and production suggests that these fuels should be considered together rather than separately, separate computer programs for oil and gas have been used in the report to provide flexibility in calculations. However, it is necessary to warn against the use of the computer programs to calculate the elasticity of supply; the impact of changes in tax provisions on ability to attract capital; and the amount of price changes required to increase oil and gas reserves and deliverability.

2. Action to stimulate and accelerate discovery and development of indigenous energy resources by private industry should be taken promptly because such resources would provide the most favorable solution for energy needs. Domestic oil and gas development jointly require strong emphasis because these fuels are now and will continue to be vitally important to the Nation.

3. U.S. energy supplies, including oil and gas, are not expected to be limited by potentially discoverable resources during the 1971-1985 period. If federal policies are designed to encourage large expenditures by private industry for new supplies and for improved recovery from producing and prospective areas, including public lands onshore and offshore, then the potential exists for significant expansion of U.S. oil and gas reserves and production, possibly even beyond the amounts projected in this report.

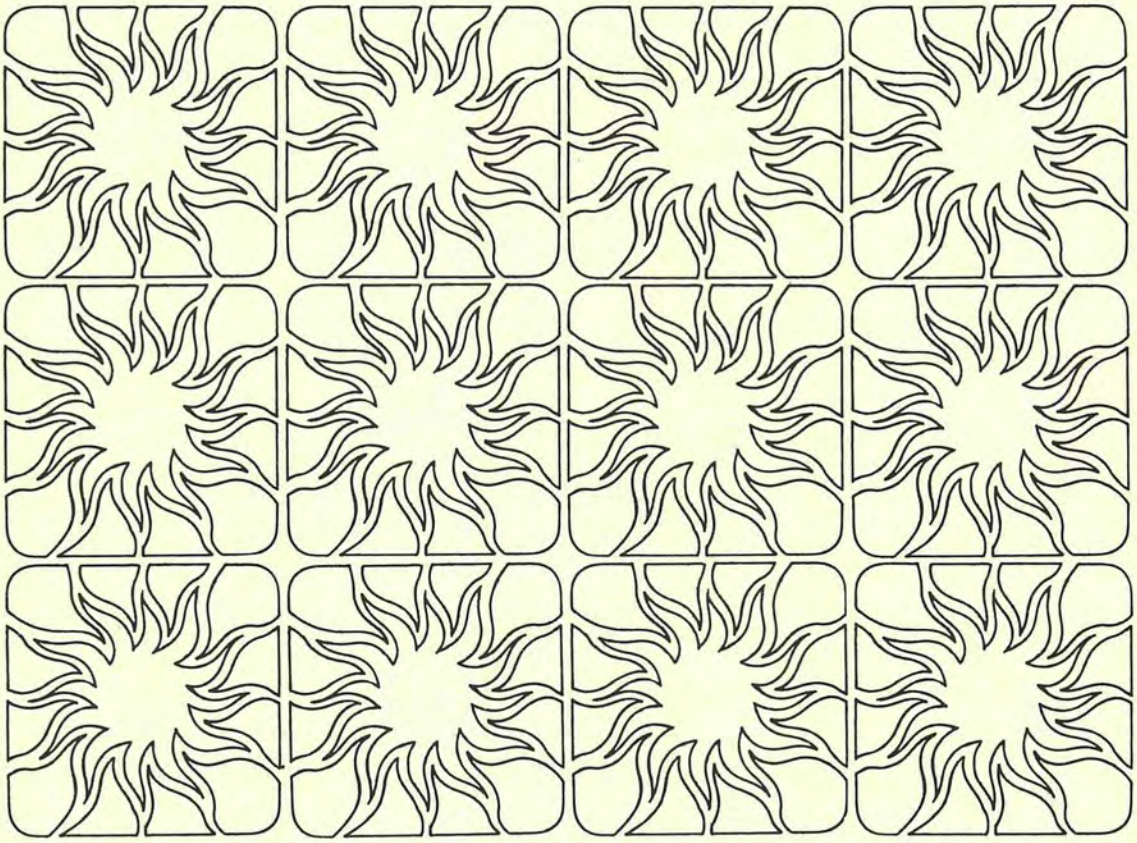
4. Prompt improvements in federal policies could result in expanded domestic supplies of energy; such improvements are essential before vast sums are committed to more expensive energy alternatives.

The National Petroleum Council sincerely hopes that this study will be of benefit to the Government in the difficult decision-making processes that lie ahead.

Respectfully submitted,

H. A. True, Jr.
Chairman

Honorable Rogers C. B. Morton
Secretary of the Interior
Washington, D.C.



U.S. Energy Outlook

A Summary Report of the National Petroleum Council

Prepared by the
National Petroleum Council's Committee
on U. S. Energy Outlook

John G. McLean, *Chairman*

with the Assistance of the
Coordinating Subcommittee
Warren B. Davis, *Chairman*

December 1972

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Preface

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary–Mineral Resources, Department of the Interior, who wrote to the Council as follows:

> A number of events affecting basic policies of government and the social and physical environment of this Nation have occurred or appear imminent which will set the stage for a new era in the petroleum industry in the United States. These events will have a decided impact on the Nation's resource capability and the structure of the industry.
>
> Because of the important and pervasive nature of the changes which may be engendered by these events, there is need for an appraisal of their impact on the future availability of petroleum supplies of the United States. . . .

The Assistant Secretary asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States. The Council was also specifically asked to indicate ranges of possible outcomes, where appropriate, and to emphasize where federal policies and programs could effectively and appropriately contribute to the attainment of an optimum long-term national energy posture (see Request Letters, Appendix 1).

Responsive to this request, the National Petroleum Council in the summer of 1970 established a Committee on U.S. Energy Outlook to carry out the study. The generous support of many cooperative organizations and people made possible a committee structure of over 200 representatives of oil, gas, coal, nuclear and other energy-related fields, as well as a number of financial experts. (For a listing of members of the Committee and its sub-groups, see Appendix 2.) This provided a uniquely broad base for the assessments made in this study.

In July 1971, the National Petroleum Council issued an interim report entitled, *U.S. Energy Outlook: An Initial Appraisal 1971-1985.* This earlier report, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

The results of the investigation since July 1971 are presented in this summary report, *U.S. Energy Outlook.* The more detailed findings of the Committee on U.S. Energy Outlook, which are the basis for this summary report, are contained in the full report of the Committee, published separately. Additionally, individual fuel task groups will publish reports that will include methodology, data, illustrations and computer program descriptions.

This request differs from customary National Petroleum Council assignments in that it encompasses, for the first time, all forms of energy. Many members of the Council have knowledge or operations relating to all the energy forms. Not all members, however, have had the requisite expertise to deal with all aspects of the report. Additional expertise was obtained from the other energy industries.

The National Petroleum Council endorses the findings and conclusions of this study.

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Introduction

The National Petroleum Council's interim study presented in the two-volume report, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, was made under the assumption that 1970 government policies and regulations, and economic climate for the energy industries would continue without major change in the 1971-1985 period. The Initial Appraisal was not designed to be a forecast of what would occur in the future; rather, it was a set of projections based on optimistic assessments of what could occur without major changes in the political and economic climate.

The detailed analyses contained in this final report have confirmed the fact that the Initial Appraisal projections may have been more optimistic than were justified. The findings of the Initial Appraisal, however, serve to demonstrate that significant changes in economic climate and government policies are essential if the present trend in the U.S. indigenous energy supply is to be substantially improved.

In this present study, U.S. energy demand, supply, logistics and financial requirements are examined in detail for the period 1971-1985. Using the Initial Appraisal as a reference point, total domestic energy demand, as well as demand in each energy consuming sector, was examined to estimate the potential variation in the Nation's future energy requirements.

These comparisons were made by analyzing the potential effects of changes that might occur in the rate of population growth, the rate of economic growth, the cost of energy, and the energy required for environmental improvement. In addition to developing a range of energy requirements, an examination was made of the impact on the Nation, its economy and our way of life that could result from restrictions on energy consumption.

Each of the individual fuel supply task groups conducted supply-economic studies. These studies considered the relationships between potentially available supplies and the future economic climate as affected by government policy. The approach was to construct four principal cases to cover the range of reasonable supply projections. These cases were then analyzed to determine the average primary fuel unit revenues required to support various levels of exploration and development, given an assumed range of investment returns. Costs and "prices" were calculated in 1970 constant dollars to eliminate all future inflationary effects.*

In defining the four cases, a number of necessary assumptions were made regarding physical, economic and government policy factors. The sensitivity of these assumptions and the effect of adoption of various government policy options were then evaluated through "parametric studies," which examined the independent effect of such variables as federal land leasing policies, environmental considerations, and variations in the taxation system on fuel supply volumes or costs.

As a starting point, this procedure required the development of *assumed* ranges of activity levels and, where relevant, success ratios. These were translated into production volumes, costs and "prices" needed to provide reasonable returns on investment. The methodology was not designed to develop activity levels or resulting supplies based on assumed prices or to quantify the incentives needed to realize the assumed levels of activity. These incentives, which are not measurable within calculated prices, include such important motivational factors to an investor as the anticipated future economic and political climate.

Where appropriate, external limitations were examined. These included such items as the amount

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* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel. For a discussion of "constant" and "current" dollars, see Glossary.

of water available in the western states to meet the needs of new synthetic oil and gas industries and the ability of the Nation's electric utilities to use the fuels that could be made available to them.

With these projections of domestic demands and supplies, it was possible to estimate the total energy imports required to meet the Nation's needs under each case. An effort was also made to determine the foreign availability of oil and gas and the practical limits of their importation. After considering limitations on foreign gas availability, the level of gas imports was projected; the remainder of needed energy imports was assumed to be supplied by oil.

To arrive at foreign oil availability, foreign energy requirements were first determined. Total world oil demand was projected, and an examination was made of the adequacy of world oil supply. Special consideration was given to Western Hemisphere supply and demand in view of the relative proximity and security of supply of these sources.

Based on domestic supply, demand and import requirements, the transportation and other logistical facilities needed to transport and process energy fuels were determined. Parametric studies on significant variables were also performed.

The capital requirements for the 15-year period needed to generate projected energy supplies and to support the necessary processing and transportation facilities were calculated. Additionally, consideration was given to the impact of the projected energy imports on the U.S. balance of trade.

The supply/demand situation from 1985 to the end of the century was also analyzed, although many more uncertainties are involved.

Recommendations for a national energy policy were drafted in response to the Secretary of the Interior's request for information on areas where federal policies and programs could contribute to attainment of an optimum long-term energy posture.

Chapter One

Summary and Conclusions

Chapter One
Summary and Conclusions

Domestic Energy Supply Outlook

For many decades, the United States has enjoyed abundant low-cost supplies of domestic energy. These fuel resources have contributed significantly to the country's economic growth, national security and quality of life.

In more recent years, because of various political, economic and environmental developments, domestic fuel supply has not grown as fast as domestic energy demand. During the next 3 to 5 years, a further deterioration of the domestic energy supply position is anticipated, and as a result fuel imports will have to be increased sharply. The Nation's dependence on imports of oil and gas increased to 12 percent of total energy requirements in 1970 and is likely to be 20 to 25 percent by 1975. The long lead times required to provide new domestic supplies make this development virtually certain.

Options for Balancing Energy Supply and Demand

The Nation must face *now* the fundamental issue of how to balance energy supply and demand most advantageously in the term beyond 1975. The major options involve (a) increased emphasis on development of domestic supplies, (b) much greater reliance on imports from foreign sources and (c) restraints on demand growth.

To some degree, all of these courses of action could contribute to solving the Nation's energy problem. The advantages, disadvantages and feasibility of each option are evaluated in this report. It is concluded that increasing the availability of domestic energy supplies is the best option available for improving the U.S. energy supply and demand balance. This approach requires increased development of domestic supplies, many of which may cost substantially more than in the past. The increased development will depend on margins between costs and prices being sufficient to attract the necessary additional investment. Accelerated development of domestic energy supplies would benefit all segments of society: employment would increase, individual incomes would rise, profit opportunities would improve, government revenues would grow, and the Nation would be more secure.

Relying on Imports to Meet Demand

The alternative of relying to a greater extent on imports would not well serve the Nation's security needs nor its economic health because of uncertainties regarding availability, dependability and price. Greater reliance on imports would also result in major balance of trade problems that could adversely affect the value of the dollar. The option of reducing energy demand growth would provide only limited help for the reasons enumerated below.

Reducing Demand Growth

Decreases in demand resulting from efficiency improvements were considered as were possible reductions from variations in the other principal factors influencing energy consumption: economic activity, population, cost of energy and environmental controls. It was judged unlikely that growth in consumption would depart significantly from the average 4.2-percent per year rate during the 1971-1985 period, as was projected in the Initial Appraisal. This is the intermediate demand growth rate used in this study. A range of 3.4-percent to 4.4-percent annual growth embraces the probable changes which could be effected. The lowest growth rate would reduce 1985 demand by 10 percent (or the equivalent of 6 million barrels per day [MMB/D] of oil) from the intermediate projection and 13.5 percent from the high projection.

Restrictions on energy demand growth could prove expensive and undesirable. Among other things, they would alter life-styles and adversely affect employment, economic growth and consumer choice. Despite possibilities for extreme changes or revisions in existing social, political and economic institutions, substantial changes in life-style between now and 1985 are precluded by existing mores and habits, and by the enormous difficulties of changing the existing energy consumption system. More efficient use of energy is desirable, and some improvement is possible and likely as energy becomes more costly. However, there are some inherent limitations in how much energy demand growth can be reduced during the next 15 years through efficiency improvements. These include the difficulties and high costs associated with altering existing equipment and the long lead times necessary before more efficient equipment can be developed and put into use.

Increasing Domestic Energy Supplies

The U.S. Energy Outlook analyses indicate that actions taken soon could increase domestic supplies in the longer term, thus reducing additional dependence on imports. No major source of U.S. fuel supply is limited by the availability of resources to sustain higher production. In this study, *resources* refer to the amount of the fuel in the ground, including that which has not yet been discovered; *reserves* are those resources that have been delineated and are capable of being developed for production; and *supplies* are the quantities that could be produced per day or per year. Despite some differences in these concepts among fuels, it is still possible to make relevant comparisons regarding the resource base and supply capabilities of individual fuels.

Oil and Gas: Oil and gas resources are sufficient to support a substantial increase in production. According to authoritative estimates,* U.S. oil and gas resources, much of which remain to be discovered, are sufficient to provide twice the 93 billion barrels of oil and three times the 393 trillion cubic feet (TCF) of gas produced through 1970. However, a substantial part of the undiscovered portions of these oil and gas deposits is believed to be located in less accessible areas and, thus, will be generally more costly than prior discoveries.

Coal: Coal is abundant. The U.S. Geological Survey estimates the Nation's coal resources at 3.2 trillion tons. Of this total about 150 billion tons of recoverable coal are presently known to be located in formations of comparable thickness and depth to those being mined by present technology. Maximum projected production in the next 15 years would use less than 10 percent of the 150 billion tons. This modest utilization of total coal reserves includes the output of coal for making synthetic fuels.

Uranium: Domestic uranium resources minable at reasonable costs are adequate to support the production of uranium needed to meet cumulative requirements through 1985. The Atomic Energy Commission (AEC) currently estimates there are 700,000 tons of uranium resources minable at a cost up to \$8/lb. of U_3O_8 and 1.6 million tons at a cost up to \$15/lb. of U_3O_8.

The dollar costs estimated by the AEC do not necessarily represent the market price which would stimulate exploration and development of these resources. However, they are useful to provide a basis for judgment as to the existence of proved and potential reserves in known deposits and uranium districts. In addition, the prospects for locating other ore bodies in partially explored and unexplored areas are good.

Oil Shale: Oil shale deposits in the western United States are estimated to contain 1.8 trillion barrels of crude shale oil. Of this amount, 129 billion barrels are in zones that contain over 30 gallons of oil per ton of shale in seams exceeding 30 feet in thickness. Within these richer zones, attention in this study was focused on tracts containing 54 billion barrels, which are considered to be the most economically recoverable. However, less than 6 billion barrels of recoverable reserves are needed to support the maximum production that could be developed by 1985 when considering limitations imposed by construction time and environmental and leasing constraints.

In addition to an ample resource base, development of fuel supplies requires the opportunity to explore prospective areas, the availability of technical competence and exploratory success. These

* NPC, *Future Petroleum Provinces of the United States* (July 1970); *Potential Supply of Natural Gas in the United States (as of December 31, 1970)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1971).

prerequisites must be accompanied by adequate profitability after taxes to provide incentives for investment. These physical and economic factors were investigated under different sets of assumptions. Because there is considerable uncertainty regarding future conditions, no one case could be selected as most probable. Rather, the analysis focused on four cases, spanning what was judged to cover a probable range of future outcomes. Any one of the cases described in this report could occur under various conditions.

The high end of the calculated supply range (Case I) would be difficult to attain because it requires a vigorous effort fostered by early resolution of controversies about environmental issues, ready availability of government land for energy resource development, adequate economic incentives, and a higher degree of success in locating currently undiscovered resources than has been the case in the past decade. The low end of the range of supply availability (Case IV) represents a likely outcome if disputes over environmental issues continue to constrain the growth in output of all fuels, if government policies prove to be inhibiting, and if oil and gas exploratory success does not improve over recent results. Two intermediate appraisals (Cases II and III) were also developed, with the higher supply Case II assuming improvement in finding rates for oil and gas, and a quicker solution to problems in fabricating and installing nuclear power plants.

Two further points of perspective relating to the cases in this study should be noted:

- In each of the four principal supply cases discussed, variations in key factors affect the production volumes and costs of various fuels. For oil and gas, as an example, accelerated application of improved recovery techniques, offshore leasing policies and tax provisions are of considerable importance. For convenience and clarity of presentation, attention has been focused on the effect of such variations on only the two intermediate cases.
- Certain policies and administrative judgments (for example, early resolution of environmental issues) would improve the prospects of attaining a high rate of growth for all fuel supplies. However, other factors could lead to different outcomes for different fuels. For instance, a high degree of exploratory success for oil and gas might lessen, to some degree, the priority on development of synthetic fuels.

Table 1 indicates that, by 1985, fuel availability under the most favorable conditions of Case I will be in the range of 50 to 100 percent greater than that under the Case IV assumptions.

The potential for increased domestic energy availability by 1985 depicted in Table 1 could be realized only with appropriate policies and economic conditions which are discussed in more detail later in this chapter.

TABLE 1

AVAILABILITY OF PRINCIPAL DOMESTIC FUEL SUPPLIES IN 1970 AND 1985

		1985			
		High Supply	Intermediate Supply		Continuation of Current Trends
	1970	Case I	Case II	Case III	Case IV
Petroleum Liquids (MMB/D)	11.3	15.5	13.9	11.8	10.4
Natural Gas (TCF/yr)	22.3	30.6	26.5	20.4	15.0
Coal (million tons/yr)*	590	1,570	1,134	1,134	1,004
Uranium (thousand tons/yr)	12.9	108.5	89.2	70.7	60.4

* Includes 47 to 339 million tons of coal production for synthetic fuels in 1985.

The Nation's Energy Picture in 1985

Energy Mix

The utilization of potential fuel supplies in meeting energy requirements by 1985 is dependent on the specific fuel needs of various consuming sectors and on the outcome of interfuel competition within certain of these sectors.

An industry advisory committee comprised of competitors is constrained from assessing interfuel competition in specific markets. Consequently, the following steps were taken in making supply/demand balances: (1) A task group composed of representatives of the electric utility industry (a regulated industry that is not constrained from considering interfuel competition because it is a customer for, not a supplier of, primary fuels) used Federal Power Commission (FPC) data to establish estimates of oil and gas consumption in the critical electric power sector. (2) After utilizing these sources and all available hydroelectric and geothermal power, coal and nuclear power were used to balance needs in this sector. No separation as to the individual supply contributions of coal and nuclear was made for the energy balances. (3) The amount of coal required to meet demand outside the electric power sector was added to energy supplies. (4) All available conventional and synthetic domestic oil and gas and projected gas imports were added to the supply. (5) Remaining energy requirements were then assumed to be satisfied by oil imports.

This procedure was used to compute the supply and consumption patterns depicted by Figure 1. Some coal and nuclear potential was unused in most cases. This result is consistent with the present use patterns of the various fuels. Coal and nuclear fuels, which are utilized principally in the electric utility sector, do not have the same degree of interchangeability in various uses as do oil and

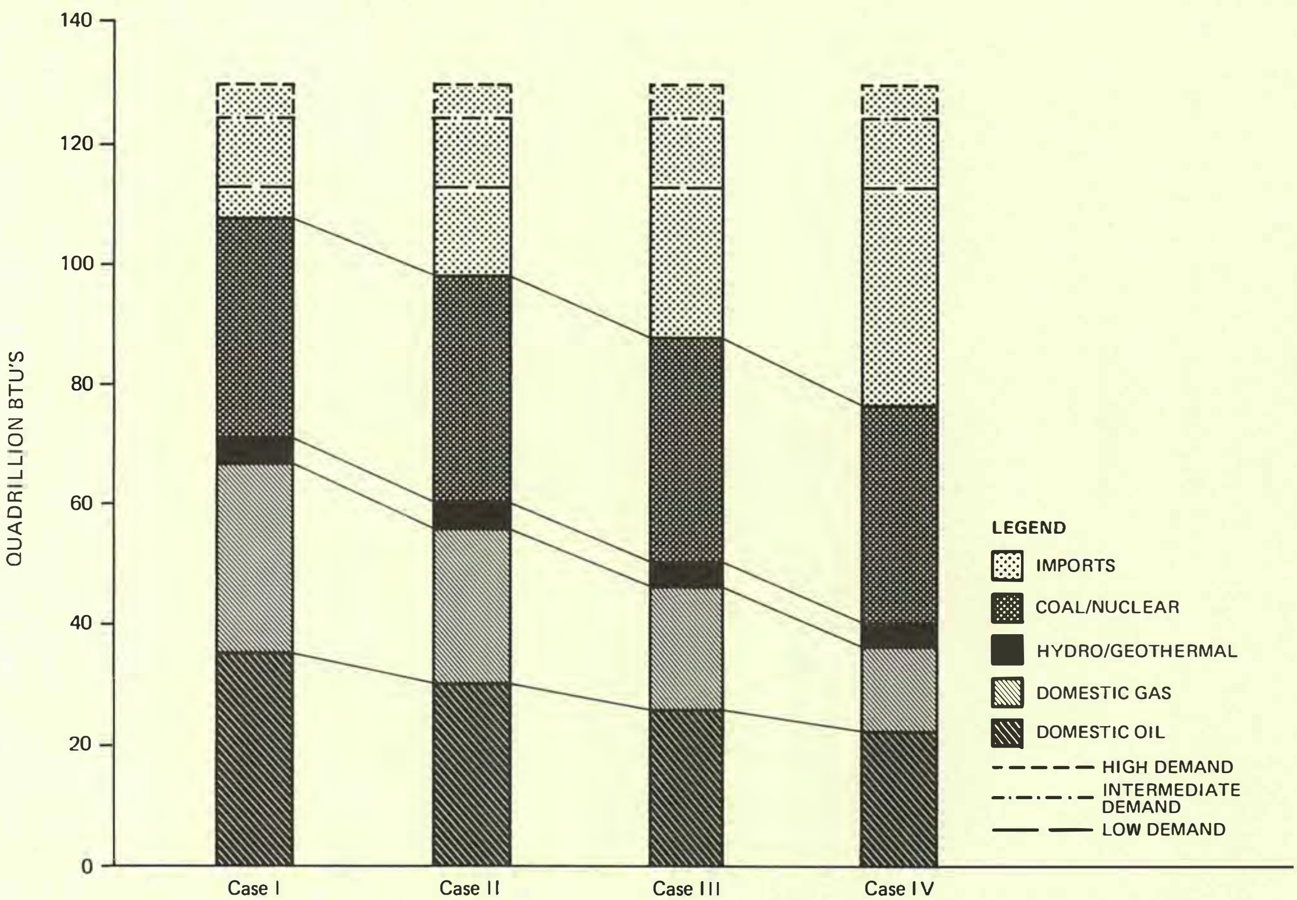

Figure 1. U.S. Energy Supply and Consumption in 1985.

gas. Thus, if the electric utility sector does not require all the potential or available supplies of coal and nuclear fuels, the excess supplies of these two fuels will remain undeveloped or unused.

Supply/demand balances were developed only with respect to the total energy situation. Supply/demand balances for individual fuels were not attempted because the availabilities of certain individual fuels have corollary effects on the demands for others.

The following conclusions, based on the intermediate energy demand and the four supply cases, can be drawn from the balances computed for 1985:

- Domestic supplies of energy, which now provide 88 percent of U.S. requirements, would provide only 62 percent if current trends continue, or 89 percent under the most optimistic supply case.
- Oil imports ranging from 3.6 to 19.2 MMB/D would be required compared to a present level of 3.4 MMB/D. By 1975, under all cases, oil imports will increase to 18 to 25 percent of energy requirements, which would amount to 42 to 51 percent of total oil supply. By 1985, oil imports will represent 6 to 33 percent of total energy supplies and 18 to 65 percent of total oil supply.
- Imports of natural gas (liquefied natural gas [LNG] and pipeline gas) may reach 5.9 to 6.6 TCF/year by 1985. This would represent about 5 percent of U.S. energy needs and from 15 to 29 percent of total gas supply. If it were not for projected limitations on gas imports imposed by Canadian gas availability and the ability to build required facilities such as LNG tankers for overseas imports, these import volumes would be even larger.
- Domestic oil and gas could provide as much as 56 percent of total energy requirements in 1985. However, if present trends continue, these fuels would contribute only 30 percent of the Nation's energy needs. By comparison, domestic oil and gas met 64 percent of total energy requirements in 1970.
- Coal and nuclear fuels could provide about 30 percent of U.S. energy requirements in 1985 in the four supply cases investigated, up from 20 percent in 1970. If a greater proportion of the Nation's energy needs could be met by electricity rather than by direct use of primary fuels, the combined potential supply of coal and nuclear fuels would be sufficient to meet up to 45 percent of 1985 U.S. energy requirements.
- Despite improved availability considered possible over current trends, natural gas supplies will be tight in relation to potential demand. Synthetic gas from coal and petroleum liquids, and natural gas from nuclear-explosive stimulation of low productivity gas reservoirs may provide from 1.8 to 5.1 TCF/year by 1985 to supplement domestic conventional natural gas supplies. Cost of these supplementary supplies will probably be greater than comparable costs required to bring forth an increase in conventional domestic gas supplies.
- The U.S. shale oil industry will come into being and could provide up to 750 thousand barrels per day (MB/D) of synthetic crude to supplement conventional liquid petroleum supplies.

Fuel "Prices"*

For each fuel, the four principal supply cases estimated the average unit revenues or "prices" required to support assumed ranges of activity levels, given an assumed range of investment returns. These analyses indicate that real energy "prices" of domestic fuels at the wellhead or mine must rise significantly by 1985. Since the "prices" cited for the fuels do not consider differences in quality, distribution costs or use characteristics, the "prices" calculated in this study cannot be meaningfully compared with each other. The projected range of percentage increases in average "prices" required to 1985 (in terms of 1970 dollars) over 1970 for individual fuels is indicated below:

- Oil at the wellhead: up 60 to 125 percent
- Gas at the wellhead: up 80 to 250 percent
- Coal at the mine: up about 30 percent
- U_3O_8: up about 30 percent.

* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel. For a discussion of "constant" and "current" dollars, see Glossary.

The above ranges would imply an average annual increase in fuel "prices" of 2 to 9 percent, though the rate of increase would not necessarily be uniform throughout the period to 1985 and would not be the same for each fuel. These are increases in real costs over and above inflation. The "prices" for U_3O_8 are based on the cost of new production.

In the years ahead, foreign energy prices are also expected to rise if recent experience is repeated. As an example, after a long period of price stability, crude oil prices in the Middle East and North Africa have risen 50 to 65 percent since the second half of 1970, and additional annual increases are already scheduled through 1975. There is no assurance that foreign energy will cost less in the future than domestic supplies.

Energy Import Implications

In the four principal cases, 1975 oil imports are expected to be more than double the 3.4 MMB/D imported in 1970. As noted earlier, 1985 oil imports are projected to range from 3.6 MMB/D to 19.2 MMB/D. Besides the possible large increases in volumes of imports, a shift in the source of imports through 1985 is indicated. The United States will become increasingly dependent on Eastern Hemisphere crude supplies. Projected Western Hemisphere petroleum supply/demand balances were developed. These indicate that not only would the export availability of potential oil and gas supplies from the Western Hemisphere outside the United States be limited, but that the Western Hemisphere itself would become more dependent on Eastern Hemisphere supplies. (A longer term exception to the limited oil availability in the Western Hemisphere is that of the Canadian tar sand resources. Maximum production from this source is projected at about 1.25 MMB/D by 1985 and almost 7 MMB/D by the end of the century.) In certain of the cases developed in this study, as much as three-fourths of U.S. oil imports in 1985 would have to come from the Eastern Hemisphere, compared with 16 percent in 1970. To obtain these imported supplies, the United States will be competing with sharply expanded requirements in Western Europe and Japan.

Net imports of natural gas in 1970, primarily from Canada, were slightly less than 0.8 TCF and represented less than 4 percent of U.S. gas consumption. While transportation and logistical obstacles may constrain their growth, natural gas imports from Canada and waterborne imports of liquefied natural gas (LNG), liquefied petroleum gas gas (LPG) or feedstocks for substitute natural gas (SNG) plants may increase more than sevenfold between 1970 and 1985. Most of these imports will be at prices higher than those now contemplated for domestic conventional production, and a large portion of these imports will come from the Eastern Hemisphere.

Three implications arise from the expected increase in imports of oil and gas.

National Security

As imports rise, the country will become increasingly dependent on the political and economic policies of a relatively small number of countries. This in turn can have important consequences on the military, political and economic security of the United States. Over the long term, the expansion of U.S. domestic energy supplies, including synthetic fuels, would provide basic safeguards against the problems and uncertainties of over-dependence on energy imports. Consideration should be given to (1) the need for additional storage to cushion the impact of possible near-term interruptions of foreign supplies and (2) desirability of utility plants being constructed to burn more than one type of fossil fuel.

Balance of Trade

Balance of trade pressures must be ameliorated. The cost of imported energy fuels, less the small sales revenue from fuel exports, results in a sizable net dollar drain. This dollar drain resulting from trade in energy fuels ($2.1 billion in 1970) will range from $9 billion to $13 billion in 1975 and from $7 billion to $32 billion annually by 1985. The threefold to fifteen-fold increase in foreign exchange requirements in 1985 above the current level will not be easily offset. Such increases will necessitate (a) adequate control of inflation by the Government and (b) close attention by U.S. industry to providing up-to-date capital equipment and improving operating efficiency. Such measures—plus export promotion programs and efforts to reduce barriers to exports of U.S. goods—will be necessary to ameliorate the foreign exchange drain of greater oil and gas imports.

Logistics

Arrangements must be made to accommodate growing oil and gas imports. The use of very large crude carriers (VLCC's) of 250,000 to 400,000 deadweight tons (DWT) is desirable for economic and environmental reasons.

At the present time, however, there are no U.S. ports capable of handling ships of those sizes. Accordingly, deepwater terminals must be built on the Gulf Coast, East Coast and Pacific Coast if the benefits of VLCC's are to be gained. Additionally, large diameter pipelines and increases in waterborne commerce into the interior will be needed.

Similar considerations are involved in the importation of natural gas, LPG, LNG and syngas feedstocks. New gas pipelines from the Canadian Arctic will be needed. LNG imports will also require substantial capital investment, both foreign and domestic, for such facilities as liquefaction plants, LNG tankers, regasification facilities and storage.

Improving the U. S. Energy Outlook

Federal government policies can accelerate or reverse adverse trends in the U.S. energy supply situation and will be a crucial determinant of the long-run energy position of the United States. Favorable policies will be required to achieve both the intermediate or high supply conditions projected in this report. If, however, government policies remain essentially the same as at present, domestic fuel production may not even be as high as the lowest supply condition described in Case IV.

The long lead times required for orderly development of energy resources make it essential that national energy objectives and sound enabling policies be established promptly. This will provide guidance to investors about the climate for expanded programs to develop domestic energy supplies. Investors will be seeking some assurance that future changes will not jeopardize the capital investments risked in efforts to provide energy to meet increasing demand.

To find, develop and process the primary energy supplies projected in Cases I-IV of this study, capital requirements will range from more than $200 billion to over $300 billion for the 1971-1985 period. In addition, electric generation and transmission facilities will exceed $200 billion. Thus, total capital requirements will be in the range of $450 billion to $550 billion.

The energy industries must earn sufficient returns on investments to provide needed capital from retained earnings and to attract additional equity and debt capital from outside sources. Higher prices for energy will be required to attract the large sums of capital needed to expand supplies above current levels. Unforeseen major technological advances might reduce costs and investment requirements, but cannot be relied upon in the time period 1971-1985. Favorable tax provisions can limit upward price pressures as they have in the past. On the other hand, any changes imposing higher taxes on energy will require even higher prices to secure the same levels of energy supplies.

The Department of the Interior requested that this report emphasize areas where federal policies and programs can effectively and appropriately contribute to the attainment of an optimum long-term national energy posture. In response to that request, the following recommendations are set forth.

Coordinate Energy Policies

Coordination and consistency are necessary in energy policies to achieve national energy goals. Unfortunately, the more than 60 federal organizations that have specific responsibilities for various fuels, together with all the interested state and local agencies, deal with the several fuels on individual bases. Their actions are often impromptu, duplicative and divergent, if not actually conflicting. For example, standards promulgated by the Environmental Protection Agency (EPA) promote increased utilization of natural gas because of its clean burning characteristics, while Federal Power Commission policies are inhibiting an increase in natural gas supplies. Coordination of federal energy policies in the Executive Branch is necessary to provide consistent guidance on energy related matters.

Establish Realistic Environmental Standards

Realistic environmental standards are essential if energy demands are to be met and the environment improved at reasonable costs. Protection of the environment will require higher energy use to achieve cleaner air and water.

Standards for a better environment must recognize the time required to effect the desired results. They must be compatible with such other important national goals as full employment, reduction of poverty, further improvement in average living standards, and assurance of energy supplies at all times for health, comfort and national security.

Reasonable demands of society with respect to the environment can be satisfied. However, programs to assure environmental quality during the production and consumption of energy fuels will involve large sums of capital. So, in reordering its priorities, the Nation must recognize the inescapable impact of added environmental costs on supplies and prices. In providing for the Nation's future energy needs, prompt action is needed to eliminate the serious delays that have been caused by environmental issues. The Government should direct immediate attention to:

- Minimizing delays in oil and gas exploration and development, laying of pipelines, and construction of deepwater terminals and new refineries.
- Establishing effective siting and licensing procedures for nuclear power plant construction and operations which will eliminate undue delays while assuring safety.
- Accelerating development of commercially viable stack gas desulfurization technology and other means of utilizing high-sulfur fuels.
- Establishing guidelines for land restoration to ensure minimum environmental impairment in surface mining operations.

The impact of environmental considerations on the Nation's domestic energy supplies can be significant and can affect all energy fuels. Delays of authorizations for the Alaskan pipeline system are depriving the Nation of at least 2 MMB/D of crude oil and about 3 TCF/year of natural gas. Nuclear reactor plant siting and licensing delays could cost the electric utility industry an additional $5 billion to $6 billion for each year's delay during the early 1970's in nuclear plant schedules, lead to increased utilization of less efficient equipment, and reduce installed nuclear plant capacity by up to 135,000 megawatts (MWe) in 1985. Until the technology for economic stack gas cleanup is developed, or some other means of using high-sulfur coal is commercially economical, such as using syngas from coal in a combined cycle, over 40 percent of estimated coal resources east of the Mississippi River (those resources having a sulfur content of over 3 percent) will be unusuable as a boiler fuel under most air quality standards. Banning of surface mining would reduce Case I 1985 coal supply potential by approximately one-half and would essentially eliminate western coal production for making synthetic liquids and gas. Environmental regulations have already restricted the fuel options available to electric utilities so that, in many parts of the United States, they have no choice but to use imported low-sulfur fuels.

Establish Realistic Health and Safety Standards

Health and safety standards and regulations for mining should be based on reliable evidence that such regulations will, in fact, achieve desirable goals. This is particularly important in such areas as radiation control, sound abatement and dust control. The economic impact of unnecessarily restrictive regulations can curtail production of needed energy resources.

It is important to continue enforcement of the Federal Coal Mine Health and Safety Act of 1969 equitably throughout the industry and to review the results of its application in order to improve it. The features which prove to be helpful to health and safety should be retained and strengthened. Any features which reduce productivity but have little bearing on health and safety should be eliminated. The impact on coal productivity of the Mine Health and Safety Act was quite significant, with individual mines reporting 15- to 30-percent reductions in output.

Encourage Greater Development of Resources on Public Lands

At least 50 percent of the Nation's remaining oil and gas potential, approximately 40 percent of the coal, 50 percent of the uranium, 80 percent of the oil shale and some 60 percent of geothermal energy sources are located on federal lands. Proper economic incentives are essential for their effective development. However, proper incentives are of no avail unless accompanied by leasing policies and programs that open the public domain to mineral exploration and development in an orderly and timely fashion. Access to such areas is being seriously delayed or completely denied at the present time.

Government should accelerate the leasing of lands for exploration and development of energy resources by private enterprise in a manner consonant with environmental goals. Such a leasing system should provide sufficient total acreage at more frequent intervals so industry can fully deploy its skills to develop needed energy supplies. In addition, once energy resources are discovered in frontier areas the industries should be allowed to bring them to market after having provided adequate environmental safeguards.

The impact of government leasing policies on energy supplies can be quite significant. This study indicates that the largest potential for developing new domestic reserves of oil and gas in the 1971-1985 period is located in the offshore areas of the United States (Gulf Coast and California), and in frontier areas (Alaska and offshore Atlantic). To support the petroleum supplies potentially available from the offshore areas under the Case II conditions, lease sales totaling 21 million acres would be required for the 15-year period. This compares with the 7 million acres made available since 1954 on the Outer Continental Shelf (OCS). If leasing were to be restricted so that no new leases were offered in the offshore areas by the Federal Government, it could cost the country about 2 MMB/D of domestic crude oil and nearly 6 TCF/year of gas in 1985.

Federal leasing policies should recognize that coal conversion to synthetic gas and liquids will require dedication of very large blocks of coal lands in order to justify the large cost of technological development and the construction of economical processing plants. Unitization of public land coal leases should be permitted to facilitate this effort.

All lands having uranium or thorium potential should remain available for exploration and development until exploration information allows assessment of mineral values. Any new time limits placed on federal claims or leases held for uranium should take into account the long lead times associated with uranium exploration and development as well as future market requirements.

Federal leasing policy is also important in the development of oil shale land. The Mineral Leasing Act of 1920 now limits a company to one lease of a maximum of 5,120 acres. This size lease does not permit a single operator sufficient reserves either to establish a sizable, and therefore economical, operation (50 to 100 MB/D) or to take advantage of improved second generation plants by having access to reserves adequate for long-term operation. A policy that (a) makes government reserves available in adequate quantities, (b) permits individual companies to have initial holdings of at least 10,000 acres, and (c) permits additional acreage to be obtained as commercial operation proceeds would provide a spur for oil shale bidding and development.

Projection of as much as 9,000 MWe of installed electric power generation capacity in 1985 utilizing geothermal energy is reasonable only if large areas of land are available for prospecting. The success ratio in drilling during the next 5 years will have a vital bearing on future development.

Assure Water Availability for Energy Production

The maximum development of synthetic fuels production (Case I) requires both an immediate government program to provide the necessary aqueduct systems in the western United States and timely resolution of disputes over water rights or water allocations.

Continue Tax Incentives

Fiscal policies should be designed to encourage the finding and development of all energy supplies. Recent developments have had a contrary effect. For example, the 1969 Tax Reform Act alone placed an additional tax burden on the domestic petrolum industry of some $500 million per annum. Fiscal policies should encourage the creation of capital requisite for increasing energy supplies and reducing costs to the consumer. Unless more effective tax provisions are devised for all energy resources, existing measures should be retained and improved.

Long-established tax provisions for the extractive industries have historically promoted the development of energy supplies. These tax features deal with percentage depletion applicable to coal, uranium, oil, gas, oil shale and geothermal steam, and those permitting current deductions of intangible costs for oil and gas. Adverse changes in such tax provisions would prove expensive for the Nation because they would reduce supplies and lead to higher costs and prices. For instance, complete removal of the statutory depletion allowance would necessitate an immediate "price" increase on the order of $0.50 per barrel for all oil and $0.03 per thousand cubic feet (MCF) for gas; by 1985 it would necessiate increases of $0.90 to $1.00 per barrel and $0.05 to $0.07 per MCF in order to maintain a return on investment sufficient to generate and attract the capital needed to provide the supply projected. These "price" increases are over and above the increased "prices" indicated for the particular fuel cases in 1985 due to higher investment and operating costs.

Maintain Oil Import Quotas

In the interest of national security the Government has adjudged that a healthy and viable petroleum industry must be maintained. To assist in meeting this objective the United States, by a 1959 Presidential Proclamation, placed a limit on petroleum import levels.

The continuation of oil import quotas is essential primarily for three reasons:

- A secure domestic energy base is a vital element of national security; over-dependence on foreign sources can make the United States vulnerable to interruption of petroleum supply from military action or from shutdown for political reasons. Without the deterrent effect of a strong domestic oil industry, producing countries could more easily threaten economic sanctions and boycotts to significantly influence U.S. international policies. Moreover, major supply interruptions of energy imports could severely hamper the functioning of the U.S. economy.
- Elimination of oil import quotas would have an adverse effect on the U.S. economy. As noted earlier, the balance of trade problem would increase greatly if imports of foreign oil were unrestrained. Direct government revenues from lease sales, royalty payments and income taxes from domestic producers—as well as indirect revenues from employee taxes and taxes from companies supplying goods and services to the domestic oil industry—would be reduced. Employment, both within the petroleum industry and in the industries supplying goods and services to the petroleum industry would be reduced.
- Oil import quotas are needed to encourage development of all indigenous energy resources. For example, since oil exploration and gas exploration are generally joint activities using the same people, techniques and equipment, the availability of these two fuels is inextricably interrelated. Without oil import quotas, the availability of domestic gas, as well as the availability of domestic oil, would decline further. This would require the importation of large quantities of foreign gas at landed costs considerably greater than the costs for domestic gas production. Also, foreign liquids would have to be imported and gasified at substantially higher costs than domestic natural gas supplies. Development of synthetic fuels from domestic resources could be retarded by the lack of economic incentives to develop such energy sources caused by the threat of unrestricted imports at a price that would not yield an adequate return for producers of synthetic fuels.

Clearly, attaining a high level of national self-sufficiency in the energy sector at a manageable cost should be a prime national policy of any industrial country. The present import quotas provide protection against the dramatic adverse effects of unrestrained imports of foreign oil at a national cost that is considerably less than other alternatives, such as maintenance of standby production and storage capacity.

Although increased imports of oil and gas will be needed in the years immediately ahead, import control policies should be implemented in a manner that will encourage increased domestic supply availability over the long term. Although concurring with the general purpose of oil import quotas, the National Petroleum Council does not feel its responsibilities in this report extend to a detailed analysis of specific regulatory or allocation features of the present Mandatory Oil Import Program.

Investigate the Feasibility and Desirability of Greater Use of Electricity Generated from Domestic Coal and Uranium Resources

Most cases studied did not utilize all of the potential coal and uranium fuel supplies because these supplies were not needed to fuel the projected electric utility generating capacity. Policies that would help overcome barriers to more rapid development of electric generating plants and encourage wider use of electrical equipment would permit the Nation to use more of its coal and uranium resources. This would reduce projected energy imports thereby mitigating the adverse effect of such imports on national security and the balance of trade.

Maintain Uranium Import Controls

Policies for imports, enrichment operations and government stockpile disposal should continue to encourage the growth of the domestic uranium mining industry. Present import policy requires that uranium enriched in U.S. government facilities for use in domestic reactors must be of U.S. origin as necessary to ensure the existence of a viable domestic uranium mining industry. A continuation of a policy to restrict the importation of uranium is necessary if a healthy domestic industry is to survive the period of transition from supplying primarily a government market to supplying a mature commercial market.

Future demand for nuclear fuel is projected to reach levels several times greater than historical quantities. In the long term, it will become not only the major fuel for electric power generation but also a major source of energy in the United States. Uranium resources in the United States are believed to be adequate to supply the necessary nuclear fuel. However, because of long lead times involved, large investments will have to be made in exploration, mining, milling and enrichment. Investments in domestic exploration and production of uranium concentrates are unlikely to be forthcoming unless government import policy encourages suppliers to make the long-range plans and commitments necessary to minimize U.S. dependence upon foreign sources of uranium.

The program proposed by the AEC in March 1972 for operation of government enrichment facilities and disposal of the government-owned stockpile is reasonable in conjunction with present import policy if adequate economic incentives can be developed to lead domestic suppliers to promptly initiate and maintain sharply increased domestic uranium supply capability. However, when a condition of oversupply leads to erosion of investment in domestic supply capability, the program for disposal of the government stockpile should cease and the existing stockpile be reserved for emergency use.

Allow Field Prices of Natural Gas to Reach Their Competitive Level

Despite the superior characteristics of natural gas, domestic prices of this fuel are held by the FPC to a fraction of the price of substitute fuels. This results in a paradoxical situation in view of present and prospective major supply shortages. At the same time that the Government engages in this supply-limiting action, serious consideration is given by Government and industry to the importation of natural gas at substantially higher prices, thus illustrating the contradictions in current regulatory policies.

As a result of these artificially low prices, reserve additions (excluding North Slope) in the last 3 years have averaged about 9.5 TCF/year while consumption has exceeded 21 TCF annually. The FPC's recently proposed optional pricing mechanism and current emergency pricing provisions are apparent admissions that the area rate prices now in existence fail to provide the needed incentives for additional exploration and production of natural gas. However, these recent changes in FPC regulations are inadequate measures; optional pricing is contingent on so many restrictions and qualifications that this proposal is of questionable value. Natural gas prices and the prices of gas manufactured from petroleum liquids or coal and liquefied gas imported from abroad should be freed to reach market clearing levels, thereby (a) encouraging exploration for new reserves, (b) stimulating development of new sources of supply and (c) discouraging the consumption of gas in low priority uses. Permitting market forces to work is certainly a better solution than to continue the counterproductive regulation of gas prices and thereby the arbitrary allocation of supplies.

Rely Primarily on Private Enterprise

The Federal Government should establish an economic and political climate which is conducive to energy development by private enterprise. An earlier section indicated the necessity and benefits of restraining imports of energy. Within the broad limits set by government import controls, private competitive enterprise will continue to be the best and lowest cost method of meeting energy needs. Competitive markets are a particularly effective mechanism for determining price levels necessary to balance demand and supply. The complex operation of market forces will best serve consumers and the national interest in (a) providing energy in the amounts needed and in the forms preferred for environmental reasons, (b) promoting efficient use of energy, and (c) allocating resources among energy activities. The results of this study clearly indicate that there is a substantial capability on the part of U.S. industry to provide additional energy from domestic resources, given the opportunity and incentives to do so. To approach the full potential of U.S. energy resources indicated in this study will require the ingenuity and effort of thousands of firms, ranging from small to large, and of millions of people.

Expand Research

This study indicates that additional research is required in such fields as: (a) exploration methods and equipment, (b) the production of synthetic fuels, (c) more efficient production and use of energy, (d) coal mining technology, (e) greater recovery of oil and gas reserves and (f) development of new energy forms. The extent to which such research is undertaken will, however, depend on establishment of an economic and regulatory climate that will permit attractive returns to those fuel suppliers conducting such research.

Benefits from technological advances could be sizable. Chapter Six deals more extensively with the potential for technology to aid in improving the Nation's energy position in the latter years of this century.

Historically, research expenditures by the oil and gas industry have primarily been privately funded, as is the case with most American industries. On the other hand, other fuel suppliers, particularly coal and nuclear, have relied largely on governmental funding. The National Petroleum Council endorses continued reliance on private industry as the principal source of funds for oil and gas research and takes no position on the optimal way to fund research in other fuel areas.

Supplies of clean, secure energy fuels will become increasingly tight over the next 3 to 5 years. This condition will become more severe in the longer term if present trends and policies continue. The potential for significantly reducing U.S. energy demand through 1985 without restricting economic growth and consumer choice is limited. The most obvious and necessary corrective action is to encourage the development of domestic supplies of all forms of energy.

Such an approach will enhance national security, ensure freedom of consumer choice, help mitigate the growing trade deficit caused by importing more of the Nation's energy requirements, and promote economic growth. Most Americans would benefit from such a program: more jobs would be created, individual incomes would rise, industrial profits would improve, and government revenues from lease sales, royalties and taxes would increase. However, the potential for improving the U.S. energy situation in the 1980's can only be realized if the economic climate is favorable and sound national policies are adopted and implemented soon.

Chapter Two

Energy Supply and Demand Balances

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In this chapter projections of future U.S. energy requirements and supplies are made. The various levels (or cases) of each are discussed and then compared to determine the Nation's future needs for energy imports.

Energy Demand Findings

The Initial Appraisal indicated that U.S. energy consumption would grow at an average rate of 4.2 percent per year during the period 1971-1985 and that the United States probably would face increasingly tighter energy supply and higher energy costs during the period. The present study has adopted the 4.2-percent growth rate as a base case and has analyzed the potential variations in future energy demand under different sets of assumptions from those used in the Initial Appraisal. The following variables were deemed to be the most significant long-range determinants of energy demand: (a) economic activity (the gross national product [GNP]), (b) cost of energy (including cost-induced efficiency improvement), (c) population, and (d) environmental controls.

These four parameters, in combination, seem to explain most of the past changes in energy demand, as indicated by special background studies. The sensitivities of energy demand relative to each of these parameters were estimated for each market sector, and the parameters were varied systematically around the Initial Appraisal estimates. In this manner, a series of energy demand cases were developed for different sets of assumptions. Since the number of possible variations is extremely large, two projections were selected (for each variable) that would bracket most of the likely energy demand cases. They are called the "high" and "low" energy demand cases, and the Initial Appraisal projection of energy consumption, which falls between these two cases, is termed the "intermediate" case.

The combination of individual parametric variations into totals—for the United States for each market sector—must be done on a judgmental basis rather than by simple quantitative formulas because the factors are not entirely independent. For example, it is believed that conditions leading to very stringent environmental standards, which are characteristic of the high demand case, probably would be associated with low economic growth and high energy costs, which are characteristics of the low case. Furthermore, it is unlikely that all factors would reach their "lows" and their "highs" simultaneously. The following tabulation presents a likely summary for the United States, which takes such relationships into account.

PROJECTIONS OF U.S. TOTAL ENERGY DEMAND UNDER THREE DIFFERENT SETS OF ASSUMPTIONS

	Growth Rate (Average Annual % Gain)			Volume (Quadrillion BTU's)	
Case	1970–1980	1981-1985	1971–1985	1980	1985
High	4.5	4.3	4.4	105.3	130.0
Intermediate (Initial Appraisal)	4.2	4.0	4.2	102.6	124.9
Low	3.5	3.3	3.4	95.7	112.5

A probability analysis indicated that approximately 85 percent of the possible variations would fall within the high/low ranges shown in the above table. Breakdowns of these ranges, by major consuming sector, appear in Table 2. While these are considered to be the probable ranges of demands based on the variables deemed to be the most significant long-range determinants of energy demand, it should be emphasized that there are many other possibilities.

This study assumes that the Nation will continue to rely on private enterprise and free consumer choice; it does not account for other potential factors that would come into play if energy consumption were reduced by supply limitations or by political decisions. In such cases, growth rates for energy and economic activity would be much lower and achievement of important social goals such as full employment, higher standards of living and improvements in the environment would be seriously impeded.

A substantial portion of the reduction in energy consumption shown in the low case is estimated to result from improvements in efficiency of en-

TABLE 2

VARIANT PROJECTIONS OF U.S. ENERGY DEMAND*
BY MAJOR CONSUMING SECTOR

	Demand Volume—Quadrillion BTU's						
	1970	1980			1985		
	Actual	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	15.8	21.1	22.4	23.4	23.9	26.6	28.5
Industrial	20.0	24.7	26.8	27.2	27.1	30.9	31.9
Transportation	16.3	23.0	23.9	24.4	26.7	28.3	29.0
Electricity Conversion	11.6	20.7	22.8	23.5	26.7	30.2	31.4
Non-Energy	4.1	6.2	6.7	6.8	8.1	8.9	9.2
Total	**67.8**	**95.7**	**102.6**	**105.3**	**112.5**	**124.9**	**130.0**

	Growth Rates—Average Annual Percent Change						
	1960-1970	1970-1980			1980-1985		
	Historical	Low†	Intermediate	High†	Low†	Intermediate	High†
Residential/Commercial	4.0	3.0	3.6	4.0	2.5	3.5	4.0
Industrial	3.4	2.1	2.9	3.1	1.9	2.9	3.2
Transportation	4.2	3.5	3.9	4.1	3.0	3.4	3.5
Electricity Conversion	7.2	5.9	6.9	7.3	5.2	5.8	6.0
Non-Energy	3.4	4.3	5.1	5.3	5.5	5.9	6.2
Total	**4.3**	**3.5**	**4.2**	**4.5**	**3.3**	**4.0**	**4.3**

* Electricity is allocated to each consuming sector and is converted at 3,412 BTU's per KWH and included in the total energy demand for the appropriate sector; the energy used by utilities for generation is shown in the Electricity Conversion category. The following figures show a reconciliation of electricity demands in these sectors with the total Electric Utility energy inputs. for the Intermediate Case only:

Demand Volumes—Quadrillion BTU's	1970	1980	1985
Residential/Commercial	2.8	5.7	7.8
Industrial	2.3	4.4	6.3
Transportation	—	0.1	0.1
Electricity Conversion	11.6	22.8	30.2
Total Utility Inputs	**16.7**	**33.0**	**44.4**

† Based on the variables deemed to be the most significant long-range determinants of energy demand.

ergy use initiated by consumers in response to higher costs, improved technology, and changed government standards (e.g., insulation in housing). Additional forced reductions in energy consumption would tend to lower economic growth and/or create losses in consumer satisfaction, which are subjective in nature and not readily expressed in quantitative terms. A few simple examples from the several consuming sectors may serve to illustrate these distinctions:

basic cases were evaluated. The general philosophy behind these four cases is as follows:

- Case I estimates the possible outcome from a maximum effort to develop domestic fuel sources. Case I assumes oil and gas drilling increases at a rate of 5.5 percent per year, and a high projection of oil and gas discovered per foot drilled. The nuclear power projections are based on the assumption that all new base-load generating plants ordered between now and 1985 will be nuclear. Production of coal for domestic consumption is increased at a rate of 5 percent per year. Synthetic fuels are developed and produced at the maximum rate physically possible without any restrictions due to environmental problems, economics, etc.

	Methods of Reducing Energy Consumption	
Result	**More Efficient Use**	**Arbitrary Reduction in Use**
Lower home fuel consumption	Better home insulation	Lower room temperature
Lower automotive fuel consumption	Increased engine fuel economy	Reduced automobile trips
Lower factory use of fuel	Installation of better machinery	Reduced factory output
Lower electric fuel requirement	Improved power plant heat rate: same light, same air conditioning	Reduced electricity consumption: less light, less air conditioning

Energy Supply Analysis

The studies that followed the Initial Appraisal have been directed primarily toward quantitative evaluation of government policies and industry actions that might increase indigenous energy supplies. There are many parameters affecting energy supplies that can be varied when making studies of this character, such as prices, exploratory activity and results, mineral leasing provisions, mineral tax laws, etc. The number of parameters that could be varied is multiplied by the fact that there are several possibilities to be considered within each of these broad categories. To attempt to treat each variation in combination with all possible variations of all other parameters would result in constructing thousands of theoretical cases. It was therefore necessary to select a limited number of combinations for in-depth analysis. (The component parameters were varied in numerous parametric studies. Their impacts are discussed throughout this report.)

Accordingly, for each primary fuel, four principal supply cases (designated I through IV) were developed, and the effects of variations in each of a series of parameters on one or more of these

- Case IV, the lowest supply case, assumes that recent trends in U.S. oil and gas drilling activity and the success from such efforts will continue; the siting and licensing problems with nuclear plants will continue; the incentives to develop new coal mines will not improve; and environmental constraints will continue to retard development of resources. This case results in a continued deterioration of the Nation's energy supply posture and is generally less optimistic than the Initial Appraisal.
- Case II assumes a less optimistic future supply picture than Case I. Oil and gas drilling activity grows at a lower rate—3.5 percent per year—than in Case I but with the same finding rates per foot drilled. For nuclear, Case II assumes problems in manufacture

and installation lead times will be solved quickly. Coal production is increased at a rate of about 3.5 percent per year. Synthetic fuels are developed and produced at a moderate buildup rate.

- Case III assumes that there will be improvement over Case IV but not to the level of Case II in the development of indigenous energy supplies. Oil and gas *drilling* grows at the same average annual rate of 3.5 percent per year experienced in Case II, but the trends of oil and gas *finding* per foot drilled are lowered to those of Case IV which reflect recent actual experience. The development of nuclear power proceeds at about the rate in the AEC's most favorable forecast. There is no significant difference between Cases II and III for coal and synthetics.

Potential Domestic Supply Availability

The total potential domestic energy supply availability was determined by combining the projections of the various fuel supply task groups under the conditions described for each of the four supply cases. The results of this compilation for the years 1975, 1980 and 1985 are given in Tables 3 and 4. Table 3 provides fuel availability in units of measurements that are conventionally used for each fuel. These data are restated in Table 4 as

TABLE 3
POTENTIAL DOMESTIC ENERGY SUPPLY AVAILABILITY
(Data in Conventional Units)

Year		Units	Initial Appraisal	Case I	Case II	Case III	Case IV
1975	Oil—Domestic Liquid Production	MMB/D	11.08	10.24	10.19	9.75	9.62
	—Shale Syncrude	MMB/D	0	0	0	0	0
	—Coal Syncrude	MMB/D	0	0	0	0	0
	Subtotal—Oil	MMB/D	11.08	10.24	10.19	9.75	9.62
	Gas—Domestic Production	TCF/yr	19.8	23.7	23.6	22.0	21.8
	—Nuclear Stimulation	TCF/yr	0	0	0	0	0
	—Syngas (Coal)	TCF/yr	0	0	0	0	0
	Subtotal—Gas	TCF/yr	19.8	23.7	23.6	22.0	21.8
	Hydroelectric	Billion KWH/yr	271	271	271	271	271
	Geothermal (Capacity)	MWe	1,500	1,500	1,500	1,500	1,500
	Coal	MMT/yr	621	665	621	621	603
	Nuclear (Capacity)	MWe	59,000	64,000	64,000	64,000	28,000
	Nuclear (U_3O_8)	MT/yr	18.4	19.1	19.1	19.1	11.5
1980	Oil—Domestic Liquid Production	MMB/D	11.80	13.58	12.94	11.61	8.90
	—Shale Syncrude	MMB/D	0	.15	.10	.10	0
	—Coal Syncrude	MMB/D	0	.08	0	0	0
	Subtotal—Oil	MMB/D	11.80	13.81	13.04	11.71	8.90
	Gas—Domestic Production	TCF/yr	17.5	25.9	24.3	20.4	17.3
	—Nuclear Stimulation	TCF/yr	0	.2	.1	.1	0
	—Syngas (Coal)	TCF/yr	.2	.6	.4	.4	.2
	Subtotal—Gas	TCF/yr	17.7*	26.7	24.8	20.9	17.51
	Hydroelectric	Billion KWH/yr	296	296	296	296	296
	Geothermal (Capacity)	MWe	4,500	10,250	5,250	4,500	2,500
	Coal	MMT/yr	734	851	734	734	705
	Nuclear (Capacity)	MWe	150,000	188,000	188,000	150,000	107,000
	Nuclear (U_3O_8)	MT/yr	34.2	50.9	45.6	36.5	29.1
1985	Oil—Domestic Liquid Production	MMB/D	11.08	15.46	13.89	11.83	10.38
	—Shale Syncrude	MMB/D	.10	.75	.40	.40	.10
	—Coal Syncrude	MMB/D	0	.68	.08	.08	0
	Subtotal—Oil	MMB/D	11.18	16.89	14.37	12.31	10.48
	Gas—Domestic Production	TCF/yr	14.5	30.6	26.5	20.4	15.0
	—Nuclear Stimulation	TCF/yr	0	1.3	.8	.8	0
	—Syngas (Coal)	TCF/yr	.5	2.5	1.3	1.3	.5
	Subtotal—Gas	TCF/yr	15.0*	34.4	28.6	22.5	15.5
	Hydroelectric	Billion KWH/yr	316	316	316	316	316
	Geothermal (Capacity)	MWe	7,000	19,000	9,000	7,000	3,500
	Coal	MMT/yr	863	1,093	863	863	819
	Nuclear (Capacity)	MWe	300,000	450,000	375,000	300,000	240,000
	Nuclear (U_3O_8)	MT/yr	59.3	108.5	89.2	70.7	60.4

* Does not include 0.4 TCF SNG from naphtha reported in Initial Appraisal as domestic supply.

TABLE 4
POTENTIAL DOMESTIC ENERGY SUPPLY AVAILABILITY
(All Data x 10^{12} BTU's/Year)

		Initial Appraisal	Case I	Case II	Case III	Case IV
1975	Oil—Domestic Liquid Production	22,789	20,735	20,630	19,754	19,502
	—Shale Syncrude	0	0	0	0	0
	—Coal Syncrude	0	0	0	0	0
	Subtotal—Oil	22,789	20,735	20,630	19,754	19,502
	Gas—Domestic Production	20,430	24,513	24,300	22,766	22,421
	—Nuclear Stimulation	0	0	0	0	0
	—Syngas (Coal)	0	0	0	0	0
	Subtotal—Gas	20,430*	24,513	24,300	22,766	22,421
	Hydroelectric	2,840	2,990	2,990	2,990	2,990
	Geothermal	120	120	120	120	120
	Coal	16,310	16,650	15,554	15,554	15,100
	Nuclear	3,340	4,000	4,000	4,000	1,661
	Total Potential Supplies	**65,829**	**69,008**	**67,594**	**65,184**	**61,794**
1980	Oil—Domestic Liquid Production	24,323	27,758	26,456	23,789	18,112
	—Shale Syncrude	0	296	197	197	0
	—Coal Syncrude	0	175	0	0	0
	Subtotal—Oil	24,323	28,229	26,653	23,986	18,112
	Gas—Domestic Production	18,030	26,746	25,043	21,041	17,906
	—Nuclear Stimulation	0	206	103	103	0
	—Syngas (Coal)	190	512	329	329	165
	Subtotal—Gas	18,220*	27,464	25,475	21,473	18,071
	Hydroelectric	3,033	3,240	3,240	3,240	3,240
	Geothermal	343	782	401	343	191
	Coal	19,928	21,200	18,284	18,284	17,550
	Nuclear	9,490	11,349	11,349	9,787	6,788
	Total Potential Supplies	**75,337**	**92,264**	**85,402**	**77,113**	**63,952**
1985	Oil—Domestic Liquid Production	23,405	31,689	28,477	24,346	21,426
	—Shale Syncrude	197	1,478	788	788	197
	—Coal Syncrude	0	1,489	175	175	0
	Subtotal—Oil	23,602	34,656	29,440	25,309	21,623
	Gas—Domestic Production	14,960	31,604	27,324	21,049	15,474
	—Nuclear Stimulation	0	1,341	825	825	0
	—Syngas (Coal)	560	2,269	1,208	1,208	494
	Subtotal—Gas	15,520*	35,214	29,357	23,082	15,968
	Hydroelectric	3,118	3,320	3,320	3,320	3,320
	Geothermal	514	1,395	661	514	257
	Coal	23,150	27,100	21,388	21,388	20,300
	Nuclear	21,500	29,810	25,249	20,220	16,126
	Total Potential Supplies	**87,404**	**131,495**	**109,415**	**93,833**	**77,594**

*Does not include 380 trillion BTU's SNG from naphtha reported in Initial Appraisal as domestic supply.

BTU equivalents. The BTU data are used in this report whenever it is necessary to compare fuels.

Appraisal of Limited Fuel Interchangeability

If all fuels were completely interchangeable, energy balances could be struck by adding all domestic fuel supplies and comparing the total with energy demands. The difference between domestic supply and projected consumption would be either available to be exported, or required to be imported. But all fuels are not completely interchangeable in all uses. An automobile can be converted to run on natural gas, a residential coal furnace can be changed to burn oil or gas, but an automobile or a gas or oil furnace cannot burn coal without extensive modification. Here lies the major problem of substitutability: the amount of time and capital required to convert a system—any energy system—to an alternate primary energy source. Logistical problems such as building new pipelines or railroad spurs to receive the new form of energy are also involved.

In projecting an energy balance of the various fuels, certain plausible simplifying assumptions were necessary. While oil is not completely interchangeable with other fuels in existing equipment, it could supply all the growth in any sector. Also it is uniquely required for most of the transportation sector. Gas is almost completely interchangeable. Hydropower and geothermal are used only in the electric power generation sector, but supplies of these two energy sources are small. Coal is utilized in significant quantities only in the industrial and electrical sector, and nuclear is confined to electricity generation.

The electric utility sector is the only consumer of all forms of primary energy; thus, it is the pivotal sector in developing an overall energy balance. However, projecting the utilization in the market of the several fuels requires not only an appraisal of fuel substitutability but also an assessment of interfuel competition. Such an analysis cannot properly be made by an industry advisory committee comprised of competitors. Accordingly, the Coordinating Subcommittee developed an alternative procedure as described below.

Fuels for Electricity

Electricity has a unique role in the U.S. energy outlook for three principal reasons:

- The electric utility industry is both a supplier of energy to consumers and, at the same time, is itself a major consumer of fuels.
- By 1975, this rapidly growing energy sector is expected to be the largest user of primary fuels of any energy sector in the Nation.
- The electricity sector plays a key role in preparing balances between energy demand and domestic supply of fuels.

The Electricity Task Group, consisting of electric utility representatives, was appointed to prepare evaluations of the electric utility sector's future demand for primary energy under various conditions. The group selected as their "base case" (or Condition 1) the fuel mix projections in the FPC National Power Survey and applied these to the NPC estimate of total electric power demand. This resulted in the utility fuel requirements shown in the following table:

Fuel Mix for U.S. Electric Utilities

	BTU x 10^{12}			
	1970	1975	1980	1985
Oil	2,050	3,460	4,050	4,530
Gas	3,900	3,900	3,900	3,900
Coal	7,800	8,905	14,306	13,900
Nuclear(1)	240	4,270	7,500	18,713
Hydro	2,677	2,990	3,240	3,320
Total	**16,667***	**23,525**	**32,996**	**44,363**

(1) Includes relatively minor volumes of geothermal (500 x 10^{12} BTU in 1985).

Between the end of 1972 and December 1985, the electric utility industry is projected to install some 560,000 MW of new generating facilities, approximately 85 percent (475,000 MW) in the form of nuclear or fossil fuel steam power plants. As of April 1972, nearly 191,000 MW of this total were committed, including 101,000 MW of nuclear installations. The balance of the steam plants (284,000 MW) will utilize either fossil or nuclear fuels depending on several factors. Among these are environmental constraints, variations in rates of increase of electricity demand, lead times and government policy decisions affecting fuel supplies. Present lead times are on the order of 5 years for fossil-fueled stations and 8 years for nuclear plants although increased legal and regulatory delays may further extend these lead times.

Natural gas supplies are not being discovered as rapidly as needed. If this condition persists, electric utilities in most areas of the United States will experience curtailments of service to existing gas-burning units. Therefore, exclusively gas-fueled electric generating plants can be planned only when increased supply capability can be demonstrated.

Environmental regulations in some areas of the country have virtually eliminated most types of coal as a fuel for new plants. Current technology on stack gas desulfurization systems, coal gasification, electrostatic precipitators and combustion control is not at a stage of development to permit compliance with the sulfur, nitrogen oxides and particulate restrictions currently in effect or proposed for many areas. Consequently, many electric utilities have only nuclear and oil as fuel alternatives. The nuclear alternative requires the greatest lead time from selection to actual power generation. Thus, in many parts of the United States during the next few years oil may be the only fuel which will permit electric utilities to meet customer requirements in an environmentally acceptable manner. However, coal is still an alternative in some areas.

The Electricity Task Group concluded that the fuel mix shown above is the most feasible from the point of view of electric utilities. It represents the mix which would probably evolve if the utility industry were not subjected to severe constraints on its decisions.

The Electricity Task Group also postulated five other feasible, although less probable, fuel mixes. These "conditions," and the base case (Condition 1), are shown in Table 5. Each of these six fuel conditions affected the mix, including the volume of imports, but not the amount of total fuel required by utilities. Condition 2 is essentially the same as Condition 1, except for the conversion of half of all natural gas-fired steam generating capacity to oil. Under Condition 3 greater reliance is placed on nuclear plants and half of all natural gas capacity would be converted to oil. Condition 4 assumes that the uses of coal and nuclear are limited and that natural gas is completely withdrawn for power generation purposes; this condition would require a substantial increase in oil consumption for electricity generation. Condition 5 restricts the 1985 consumption of coal and oil to their 1970 level and reduces the consumption of natural gas by 50 percent; nuclear energy would be responsible for virtually all net growth in utility requirements. Condition 6 assumes a nuclear "moratorium" after 1980 and a reduction of natural gas consumption; coal and, to a lesser extent, oil would absorb the resulting fuel deficit. The effects of these conditions are summarized in Table 5.

Energy Balances

Using the Electricity Task Group projections of utility fuel consumption shown in Table 5 and the previous general observations on equipment convertibility and fuel substitutability, simplified total energy supply/demand balances were constructed by the Committee. The assumptions underlying these balances are as follows:

- All available domestic supplies of conventional oil and gas and synthetics will be utilized.
- All available geothermal and hydroelectric capability will be utilized.
- All available gas imports will be utilized.
- Consumption of coal by sectors other than electric utilities will be as projected by the Coal Task Group in the Initial Appraisal.
- All utility primary fuel requirements not met by oil, gas, hydro or geothermal will be satisfied by coal and/or nuclear. It is emphasized that for the purpose of these balances, no attempt has been made to identify the exact contribution of coal and nuclear, only their total combined participation. (In the balances, when this combined supply was less than requirements the difference was assumed to be met with imported oil. In the majority of the balances, however, the combined potential was greater than requirements.)
- The difference between total energy demand and the sum of the foregoing fuel availabilities will be satisfied by oil imports.

This simplified approach yields total energy supply/demand balances, which are useful in assessing (a) energy imports as a percent of U.S. consumption and (b) the volume of oil imports required to meet U.S. energy demands. It does not provide fuel supply patterns for individual market sectors or geographic regions. It does not define the exact role of coal and nuclear in the electric utility sector. Neither of these deficiencies detracts from the usefulness of the resulting assessment of energy import requirements.

Tables 10 to 13 at the end of this chapter summarize the U.S. energy supply and demand bal-

TABLE 5
1985 ELECTRIC UTILITY FUEL CONSUMPTION

Condition No.*	Ratio to Year 1970				Percent of Total			
	Oil	Gas	Coal	Nuclear	Oil	Gas	Coal	Nuclear
1	2.2	1.0	1.8	78.0	10	9	32	42
2	3.2	0.5	1.8	78.0	15	4	32	42
3	3.0	0.5	1.6	85.2	14	4	29	46
4	7.8	0	1.0	71.7	36	0	18	39
5	1.0	0.5	1.0	122.0	5	4	18	66
6	4.9	0.5	2.8	31.2	23	4	49	17

* Conditions 1 through 4 are adjudged more likely than Conditions 5 and 6 by the Electricity Task Group.

ances for supply Cases I to IV, using Condition 1 (or base case) for electric utility fuels and the intermediate energy demand case.

Appendix 4 contains a description of the methods used to derive these balances and the full detail of all balances summarized in this section.

Pursuant to the previously stated assumptions underlying these energy balances, namely that no attempt was made to identify the individual respective contributions of coal and nuclear energy in the electric utility field, Table 6 compares the quantities of energy from coal and nuclear that were used in the energy balances with the maximum quantities of energy that could be obtained from these two energy forms.

TABLE 6
COMPARISON OF QUANTITIES OF ENERGY FROM COAL AND NUCLEAR

Supply Case	Energy from Coal & Nuclear	Trillion (10^{12}) BTU's		
		1975	1980	1985
I	Used in Energy Balance	18,649	26,708	36,910
	Maximum Available	20,650	32,549	56,910
II	Used in Energy Balance	18,649	27,089	37,644
	Maximum Available	19,554	29,633	46,637
III	Used in Energy Balance	18,649	27,147	37,791
	Maximum Available	19,554	28,071	41,608
IV	Used in Energy Balance	16,761	24,338	36,426
	Maximum Available	16,761	24,338	36,426

Energy Imports

The percentages of energy that would need to be imported, as derived in the energy balances in Tables 10-13 (Electricity Condition 1 and intermediate energy demand) are summarized in Table 7. Total energy imports as a percent of U.S. requirements are shown in Figure 2.

Energy imports in 1970 were about 12 percent of the U.S. energy supply. In all cases, energy imports increase sharply between 1970 and 1975. Imports as a percent of energy consumption decline from 1975 to 1985 in Case I, stay about constant in Case II, and increase in Cases III and IV. In Case IV they reach 38 percent of the energy consumption in 1980 and 1985.

Gas imports consist of pipeline natural gas from Canada, liquefied natural gas (imported in special tankers), and liquefied petroleum gas (also imported in tankers). They are projected at their maximum feasible level in all cases. Gas imports are expected to grow from about 1 quadrillion BTU's in 1970 to about 7.5 quadrillion BTU's by 1985, and in Case I, they are about half of the 1985 total imports. Under one concept, they are more than half, because part of the oil imports is made up of light oil feedstocks for the manufacture of synthetic gas.

As discussed earlier, the nature of the U.S. energy supply and consumption patterns is such that imported oil is the energy form that provides the final increment of supply. The volumes of oil imports corresponding to the percents in Figure 2 are shown in the tabulation below and in Figure 3.

Supply Case	Oil Imports(1) (MMB/D) 1970	1975	1980	1985
I	3.4	7.2	5.8	3.6
II	3.4	7.4	7.5	8.7
III	3.4	8.5	10.6	13.5
IV	3.4	9.7	16.4	19.2

(1) Electricity Condition 1 and intermediate energy demand.

The volumes cited are crude oil equivalents of the calculated BTU deficit. Some fraction of the actual import volumes will be refined petroleum products, but no effort has been made to quantify the breakdown between crude and refined products. As discussed later, the actual mix of imported crude and products will be determined to a major degree by government import policy.

Even in Case I, oil imports more than double between 1970 and 1975, and in Case IV, nearly triple. Required oil imports in 1985 range from 19.2 MMB/D in Case IV to 3.6 MMB/D in Case I.

TABLE 7

PERCENTAGES OF ENERGY IMPORTS NEEDED TO FILL SUPPLY

Supply Case	Oil Imports as a Percent of Total Oil Supply*				Gas Imports as a Percent of Total Gas Supply				All Imports as a Percent of Total U.S. Energy Supply			
	1970	1975	1980	1985	1970	1975	1980	1985	1970	1975	1980	1985
I	26	42	30	18	4	5	12	15	12	20	16	11
II	26	43	37	38	4	5	14	18	12	20	19	20
III	26	48	48	53	4	5	16	22	12	23	26	28
IV	26	51	66	65	4	5	18	29	12	26	38	38

* A portion of the energy supply consists of gas reformed from petroleum liquids. To the extent that domestic liquids are reformed into gas, a corresponding increase in imported liquids would be required. Accordingly, for the purpose of the following energy balances, the energy in liquids reformed into gas and the input energy in gas reformed from liquids were both considered imported.

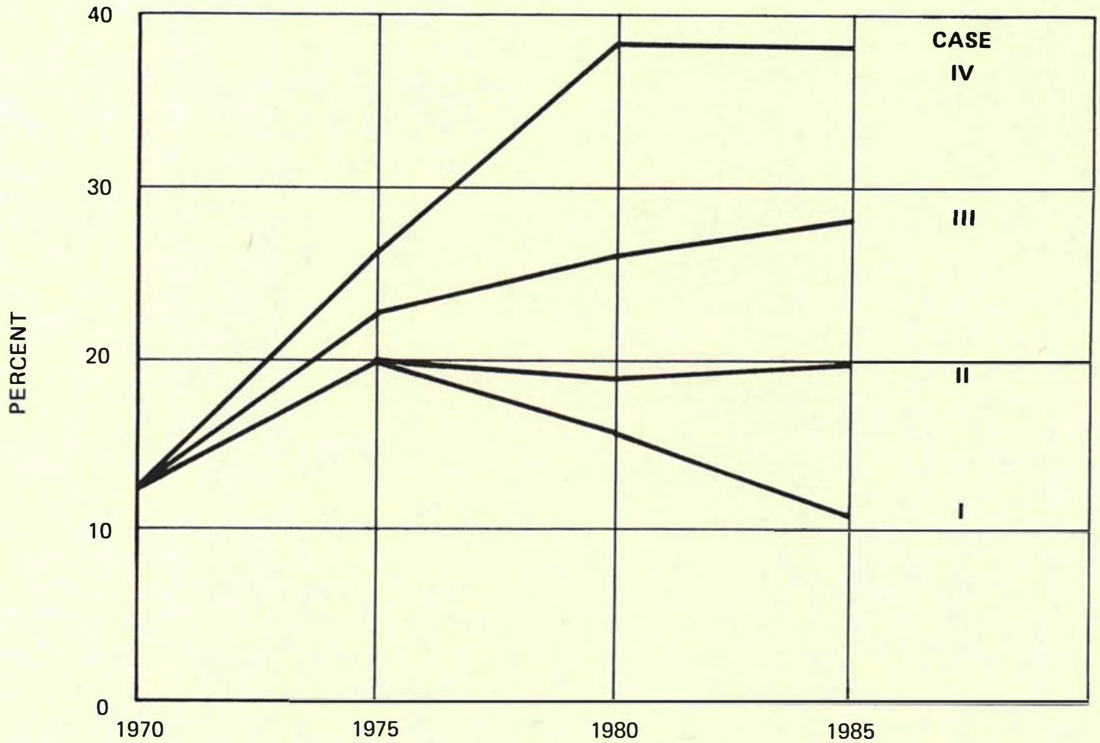

Figure 2. U.S. Energy Imports as Percent of Total U.S. Energy Consumption.

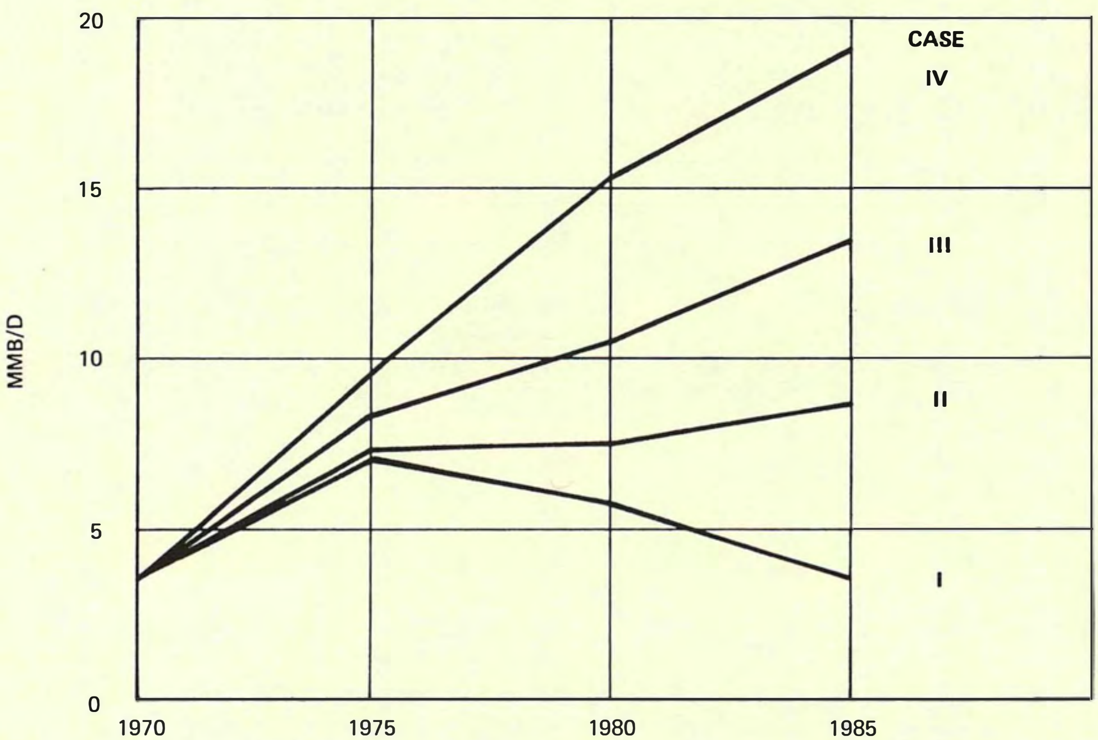

Figure 3. Oil Imports.

Sensitivity Analysis of Supply and Demand Balances

The effects on the supply and demand balances were investigated for (a) variations in the electric utility fuel mix, (b) different combinations of supply cases for individual fuels, (c) variations in demand requirements, and (d) increased use of electrical energy.

Electric Utility Mix

Three of the assumptions in preparing the supply and demand balances were that (a) all domestic supplies of oil and gas would be used, (b) all available gas imports would be utilized, and (c) oil imports would be the balancing element. Thus, any increase or decrease in oil and gas used by utilities would raise or lower oil imports by the same amount.

Table 8 shows this effect on required oil imports as electric conditions are varied.

For Conditions 1, 2 and 3, the percentage of oil-plus-gas in the utility fuel mix in 1985 remains essentially constant at 18 to 19 percent, and the required oil imports also remain essentially constant at about 13.5 MMB/D. For Conditions 4 and 6, when the oil-plus-gas share is increased to 36 percent and 27 percent respectively, the required oil imports are increased to 17.1 and 15.2 MMB/D. For Condition 5, the oil-plus-gas share is decreased to 9 percent and required oil imports are decreased to 11.7 MMB/D. For every 5 percent of the electricity requirements provided by oil and gas, oil imports change 1 MMB/D.

Different Combinations of Supply Case for Individual Fuels

The preceding analyses assume similar conditions were influencing the supply of each indigenous fuel. Thus, for example, the Case III energy supply condition was the summation of Case III conditions for each principal major fuel (line **a** in Table 9). In this section, different combinations of the four basic supply cases for individual fuels were investigated (lines **b**, **c**, **e** and **f**). The results of these various combinations of required fuel and required oil imports are shown in Table 9.

In comparison with Case III, if either oil or gas experiences the higher discovery rate associated with Case II, required oil imports are reduced. (The amount imports are reduced is apparent by comparing lines **b** and **c** with **a**.) With coal and nuclear at very high supply levels (Case I), the amount of oil imports is reduced only modestly. (Compare lines **d** and **e**.) This is because there are not enough electric utility plants in the United States to use the additional fuel.

On the other hand if domestic supplies of oil and gas are increased to Case I levels, there will be a major decrease in oil imports. (The extent of

TABLE 8

EFFECT OF VARIED ELECTRIC CONDITIONS ON OIL IMPORTS

	Oil Imports* (MMB/D)					
	1975 Case		1980 Case		1985 Case	
Condition	II	III	II	III	II	III
1	7.4	8.5	7.5	10.6	8.7	13.5
2	7.4	8.5	7.5	10.6	8.7	13.5
3	6.9	8.1	6.9	10.2	8.5	13.3
4	7.9	9.0	10.5	13.7	12.3	17.1
5	7.9	9.0	10.5	13.7	6.6	11.7
6	6.9	8.1	6.9	10.2	10.4	15.2

* Intermediate energy demand used for all calculations.

TABLE 9

EFFECTS OF COMBINATIONS OF REQUIRED FUELS ON OIL IMPORTS

	Supply Case Numbers*					Oil Imports (MMB/D)		
	Oil	Gas	Coal	Nuclear	Others	1975	1980	1985
(a)	III	III	III	III	III	8.5	10.6	13.5
(b)	II	III	III	III	III	8.1	9.2	11.2
(c)	III	II	III	III	III	7.8	8.9	10.9
(d)	IV	IV	IV	IV	IV	9.7	16.4	19.2
(e)	IV	IV	I	I	IV	8.8	15.0	18.5
(f)	I	I	IV	IV	IV	8.1	7.6	6.5

* Electrical Condition 1 and intermediate demand case.

the import reduction is apparent by comparing lines **d** and **f**.)

Variation in Demand

When all three demand cases were applied to the balance for intermediate supply cases (Cases II and III), the following projections or required oil imports resulted:

	Oil Imports—Required (MMB/D)			
	Supply Case II[(1)]		Supply Case III[(1)]	
Energy Demand Case	1980	1985	1980	1985
Low	4.2	2.8	7.4	7.6
Intermediate	7.5	8.7	10.6	13.5
High	8.8	11.1	11.9	15.9

(1) Electrical Condition 1.

In comparison with the intermediate case, the low energy demand case would reduce required oil imports in 1985 by about 6 MMB/D, and the high case would increase them by about 2.5 MMB/D.

Figure 4 compares Cases II and III in combination with the three demand cases for the period 1970-1985. Both illustrations depict the expected growing role of imports in supplying U.S. energy requirements.

Increased Use of Electrical Energy

All of the energy balances previously discussed used the Energy Demand Task Group's projection of total electric utility primary energy demand. In all balances, energy imports were required, but in some of these balances not all domestic energy supplies were utilized. As discussed earlier, nuclear energy and coal consumption are concentrated in electric power generation because they cannot readily be employed in other energy applications. Thus, supplies of these two fuels not needed by electric utilities will go unutilized. It was deemed appropriate, therefore, to examine the effects of substituting electrical energy generated by domestic coal and nuclear fuel for imported oil and gas. Such a substitution would call for an increase in construction of electric power plants to utilize these surplus fuels and would require electric utility fuel consumption to grow 8.8 percent per year. An increase in the electric utility industry's annual growth rate of 2.1 percentage points above the 6.7 percent projected by the Energy Demand Task

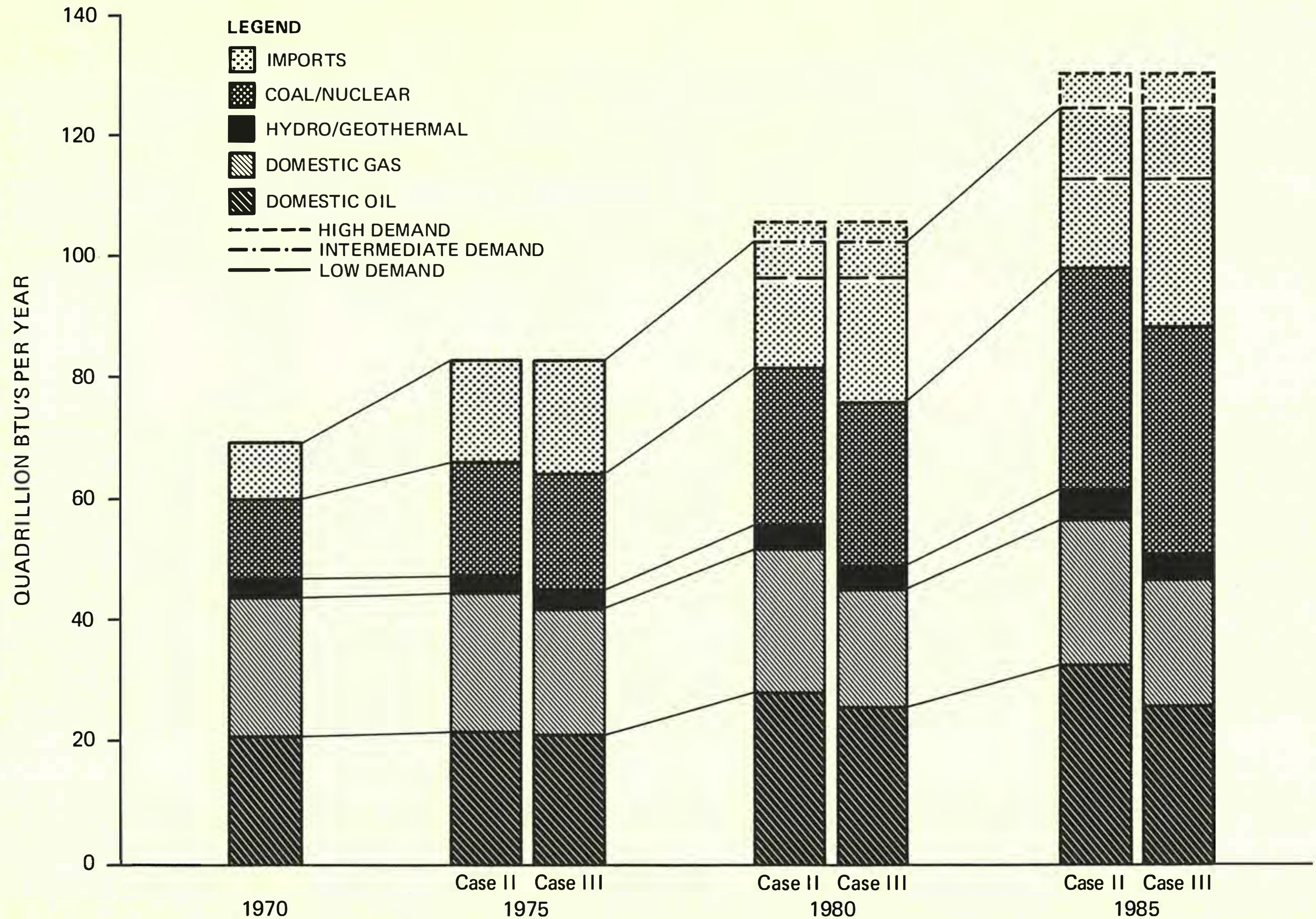

Figure 4. Energy Supply and Consumption, Cases II & III.

Group would be difficult. If there were no change in system load factors, additional capital expenditures for generating and transmission facilities could range as high as $130 billion to $150 billion (in constant 1970 dollars) over the 15 years 1971-1985. If, as is more likely, much of the incremental electricity consumption were due to increased electric space and process heating, there would be a tendency toward improved load factors, and the incremental capital requirements for power plants and transmission lines would be correspondingly less. Considerable additional expenditures on distribution systems would be necessary in either case. No attempt was made to calculate the corollary effects on overall capital requirements for energy of the high electricity case although some offsetting reductions in capital expenditures in other energy areas may occur.

The following tabulation shows the comparison of the growth rates for the electric utility sector in the intermediate demand case and the high electricity case.

	Fuel Requirements BTU x 10^{12} per Year			
	1970	1975	1980	1985
Intermediate Demand Case	16,695	23,525	32,996	44,363
Additional	0	2,001	5,841	14,929
NEW TOTAL	**16,695**	**25,526**	**38,837**	**59,292**

	Growth Rates Average Annual %			
	1970-75	1975-80	1980-85	1970-85
Intermediate Demand Case	6.9	6.9	6.0	6.7
Additional	1.9	1.9	2.8	2.1
NEW TOTAL	**8.8**	**8.8**	**8.8**	**8.8**

Table 14 shows that in 1975 and 1980, this increase is not enough to eliminate imports, but in 1985 only 88 percent of the total coal and nuclear supplies available are utilized in order to satisfy total U.S. energy demand solely from domestic sources. It should be noted, however, that under these conditions, in 1985 over 47 percent of U.S. energy is being consumed for the generation of electricity versus 25 percent in 1970.

The following tabulation compares the Case I import levels with those of the high electricity case for the years 1975, 1980 and 1985.

	Oil Imports Required (MMB/D)		
	1975	1980	1985
Case I	7.2	5.8	3.6
High Electricity Case	6.3	3.0	0.0

TABLE 10
PROJECTED ENERGY BALANCE FOR UNITED STATES–CASE I

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil–All Sources	21,048	20,735	28,229	34,656	31	25	27	28
Gas–All Sources	22,388	24,513	27,464	35,214	33	29	27	28
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	782	1,395	*	*	1	1
Coal & Nuclear Utilized	13,302	18,649	26,708	36,910	20	22	26	29
Total Domestic Supply	**59,422**	**67,007**	**86,423**	**111,495**	**88**	**80**	**84**	**89**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	15,274	12,258	7,547	11	18	12	6
Gas (Excluding Gas from Liquids)	950	1,200	3,900	5,900	1	2	4	5
Total Imported Supply	**8,405**	**16,474**	**16,158**	**13,447**	**12**	**20**	**16**	**11**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	16,650	21,200	27,100	98	81	65	48
Nuclear Supply	240	4,000	11,349	29,810	2	19	35	52
Total Coal & Nuclear Available	**13,302**	**20,650**	**32,549**	**56,910**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,735	27,758	31,689	74	58	69	74
Syncrude from Shale	0	0	296	1,478	0	0	1	4
Syncrude from Coal	0	0	175	1,489	0	0	*	4
Imports (Including Liquids for Gasification)	7,455	15,274	12,258	7,547	26	42	30	18
Total Oil	**28,503**	**36,009**	**40,487**	**42,203**	**100**	**100**	**100**	**100**
Oil Imports to Balance–MMB/D	3.4	7.2	5.8	3.6				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,513	26,746	31,604	96	95	85	76
Gas from Nuclear Stimulation	0	0	206	1,341	0	0	1	3
Syngas from Coal	0	0	512	2,269	0	0	2	6
Imports–Pipeline	950	1,000	1,600	2,700	4	4	5	7
Imports of LNG	0	200	2,300	3,200	0	1	7	8
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,713**	**31,364**	**41,114**	**100**	**100**	**100**	**100**
Gas Imports–TCF/yr	0.9	1.2	3.9	5.9				

* Less than 0.5 percent.

TABLE 11
PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE II

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	20,630	26,653	29,440	31	25	26	23
Gas—All Sources	22,388	24,300	25,475	29,357	33	29	25	23
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	401	661	*	*	*	1
Coal & Nuclear Utilized	13,302	18,649	27,089	37,644	20	22	27	30
Total Domestic Supply	**59,422**	**66,689**	**82,858**	**100,422**	**88**	**80**	**81**	**80**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	15,592	15,823	18,420	11	19	15	15
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,100	1	1	4	5
Total Imported Supply	**8,405**	**16,792**	**19,723**	**24,520**	**12**	**20**	**19**	**20**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,554	18,284	21,388	98	80	62	46
Nuclear Supply	240	4,000	11,349	25,249	2	20	38	54
Total Coal & Nuclear Available	**13,302**	**19,554**	**29,633**	**46,637**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,630	26,456	28,477	74	57	62	60
Syncrude from Shale	0	0	197	788	0	0	1	2
Syncrude from Coal	0	0	0	175	0	0	0	*
Imports (Including Liquids for Gasification)	7,455	15,592	15,823	18,420	26	43	37	38
Total Oil	**28,503**	**36,222**	**42,476**	**47,680**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	7.4	7.5	8.7				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,300	25,043	27,324	96	95	85	77
Gas from Nuclear Stimulation	0	0	103	825	0	0	*	2
Syngas from Coal	0	0	329	1,208	0	0	1	3
Imports—Pipeline	950	1,000	1,600	2,700	4	4	6	8
Imports of LNG	0	200	2,300	3,400	0	1	8	10
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,500**	**29,375**	**35,457**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	6.1				

* Less than 0.5 percent.

TABLE 12

PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE III

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	19,754	23,986	25,309	31	23	23	20
Gas—All Sources	22,388	22,766	21,473	23,082	33	27	21	19
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	343	514	*	*	*	*
Coal & Nuclear Utilized	13,302	18,649	27,147	37,791	20	22	27	30
Total Domestic Supply	**59,422**	**64,279**	**76,189**	**90,016**	**88**	**77**	**74**	**72**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	18,002	22,492	28,526	11	22	22	23
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,400	1	1	4	5
Total Imported Supply	**8,405**	**19,202**	**26,392**	**34,926**	**12**	**23**	**26**	**28**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,554	18,284	21,388	98	80	65	
Nuclear Supply	240	4,000	9,787	20,220	2	20	35	
Total Coal & Nuclear Available	**13,302**	**19,554**	**28,071**	**41,608**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	19,754	23,789	24,346	74	52	51	45
Syncrude from Shale	0	0	197	788	0	0	1	2
Syncrude from Coal	0	0	0	175	0	0	0	*
Imports (Including Liquids for Gasification)	7,455	18,002	22,492	28,526	26	48	48	53
Total Oil	**28,503**	**37,756**	**46,478**	**53,835**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	8.5	10.6	13.5				
Memo: Gas Supply								
Domestic Natural Gas	22,388	22,766	21,041	21,049	96	95	83	71
Gas from Nuclear Stimulation	0	0	103	825	0	0	*	3
Syngas from Coal	0	0	329	1,208	0	0	1	4
Imports—Pipeline	950	1,000	1,600	2,700	4	4	7	9
Imports of LNG	0	200	2,300	3,700	0	1	9	13
Total Gas (Excluding Gas from Liquids)	**23,338**	**23,966**	**25,373**	**29,482**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	6.4				

* Less than 0.5 percent.

TABLE 13
PROJECTED ENERGY BALANCE FOR UNITED STATES–CASE IV

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil–All Sources	21,048	19,502	18,112	21,623	31	23	18	17
Gas–All Sources	22,388	22,421	18,071	15,968	33	27	17	13
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	191	257	*	*	*	*
Coal & Nuclear Utilized	13,302	16,761	24,338	36,426	20	20	24	29
Total Domestic Supply	**59,422**	**61,794**	**63,952**	**77,594**	**88**	**74**	**62**	**62**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	20,487	34,729	40,748	11	25	34	33
Gas (Excluding Gas from Liquids)	950	1,200	3,900	6,600	1	1	4	5
Total Imported Supply	**8,405**	**21,687**	**38,629**	**47,348**	**12**	**26**	**38**	**38**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	15,100	17,550	20,300	98	90	72	56
Nuclear Supply	240	1,661	6,788	16,126	2	10	28	44
Total Coal & Nuclear Available	**13,302**	**16,761**	**24,338**	**36,426**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	19,502	18,112	21,426	74	49	34	34
Syncrude from Shale	0	0	0	197	0	0	0	*
Syncrude from Coal	0	0	0	0	0	0	0	0
Imports (Including Liquids for Gasification)	7,455	20,487	34,729	40,748	26	51	66	65
Total Oil	**28,503**	**39,989**	**52,841**	**62,371**	**100**	**100**	**100**	**100**
Oil Imports to Balance–MMB/D	3.4	9.7	16.4	19.2				
Memo: Gas Supply								
Domestic Natural Gas	22,388	22,421	17,906	15,474	96	95	81	69
Gas from Nuclear Stimulation	0	0	0	0	0	0	0	0
Syngas from Coal	0	0	165	494	0	0	1	2
Imports–Pipeline	950	1,000	1,600	2,700	4	4	7	12
Imports of LNG	0	200	2,300	3,900	0	1	11	17
Total Gas (Excluding Gas from Liquids)	**23,338**	**23,621**	**21,971**	**22,568**	**100**	**100**	**100**	**100**
Gas Imports–TCF/yr	0.9	1.2	3.9	6.6				

* Less than 0.5 percent.

TABLE 14

PROJECTED ENERGY BALANCE FOR UNITED STATES–HIGH ELECTRICITY CASE

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil–All Sources	21,048	20,735	28,229	34,656	31	25	27	28
Gas–All Sources	22,388	24,513	27,464	35,214	33	29	27	28
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	782	1,395	*	*	1	1
Coal & Nuclear Utilized	13,302	20,650	32,549	50,357	20	24	32	40
Total Domestic Supply	**59,422**	**69,008**	**92,264**	**124,942**	**88**	**82**	**90**	**100**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	13,273	6,417	0	11	16	6	0
Gas (Excluding Gas from Liquids)	950	1,200	3,900	0	1	2	4	0
Total Imported Supply	**8,405**	**14,473**	**10,317**	**0**	**12**	**18**	**10**	**0**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	16,650	21,200	27,100	98	81	65	48
Nuclear Supply	240	4,000	11,349	29,810	2	19	35	52
Total Coal & Nuclear Available	**13,302**	**20,650**	**32,549**	**56,910**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,735	27,758	31,689	74	61	80	92
Syncrude from shale	0	0	296	1,478	0	0	1	4
Syncrude from Coal	0	0	175	1,489	0	0	*	4
Imports (Including Liquids for Gasification)	7,455	13,273	6,417	0	26	39	19	0
Total Oil	**28,503**	**34,008**	**34,646**	**34,656**	**100**	**100**	**100**	**100**
Oil Imports to Balance–MMB/D	3.4	6.3	3.0	0				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,513	26,746	31,604	96	95	85	90
Gas from Nuclear Stimulation	0	0	206	1,341	0	0	1	4
Syngas from Coal	0	0	512	2,269	0	0	2	6
Imports–Pipeline	950	1,000	1,600	0	4	4	5	0
Imports of LNG	0	200	2,300	0	0	1	7	0
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,713**	**31,364**	**35,214**	**100**	**100**	**100**	**100**
Gas Imports–TCF/yr	0.9	1.2	3.9	0				

* Less than 0.5 percent.

Chapter Three

Findings

Domestic Energy Supplies

Chapter Three

Findings—Domestic Energy Supplies

Findings—Oil and Gas

This section estimates the available production volumes of oil and gas and the average "prices" required to yield a range of returns on the investments necessary to provide this production. These estimates are based on projections of all pertinent variables such as drilling and finding rates, application of additional recovery techniques, costs, government policies on leasing, taxation, etc. Variations in the most important of these parameters were investigated wherever possible to provide some insight on their impact on production and required "prices."

In view of the increasing importance to the United States of imported oil and gas, the potential availability of foreign supplies of these fuels is examined in Chapter Four. The logistical problems of handling the projected volumes of domestic and foreign supplies are considered.

Domestic Oil and Gas Supply

Discoverable Resources

U.S. oil and gas supply is not expected to be limited by potentially discoverable resources during the 1971-1985 period. In a few of the more mature inland areas, most of the oil and gas now thought to be discoverable may be found by 1985. However, for the country as a whole, an estimated 385 billion barrels of oil (48 percent of the estimated ultimate discoverable oil-in-place) and 1,178 TCF of gas (63 percent of the ultimate discoverable gas reserves) remained to be found at the end of 1970.* About one-half of the remaining discoverable oil and gas reserves are in the public domain, in Alaska and offshore areas. Therefore, the importance of making leases available in these most prospective areas becomes apparent.

Cases Analyzed

Many variables influence the supplies of domestic oil and gas that can be developed and the "prices" that will be required to yield acceptable returns on investment. Two of the most significant are the finding rate and the drilling rate.

The finding rate is the volume of oil and gas found per unit of exploratory effort. This factor—which embraces an element of risk as well as exploratory skill—not only helps determine the projected supply but also heavily influences future required prices. For this reason, both high and low finding rates were used to project oil and gas supplies; the low is an extrapolation of past trends and the high rate is approximately 50 percent higher.

The drilling rate is another major factor in determining projected supplies. Over the last 10 to 15 years, drilling footage has declined at a rate of about 4- to 5-percent per year. For purposes of this study, three drilling rates were assumed over a range that varies from continuation of the current 4- to 5-percent per year decline to a growth rate of nearly 6-percent per year, a rate previously attained in the decade following World War II.

The three drilling activity projections, when combined with the two finding rate assumptions, result in a set of four principal cases—each with projected reserve additions, production rates, costs and required average "prices" to achieve specified rates of return. Another important assumption is the timing and initiation of production from the Alaskan North Slope. The combinations of the assumptions used in the four cases are outlined below.

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* NPC, *Future Petroleum Provinces of the United States* (July 1970), as modified for subsequent developments; *Potential Supply of Natural Gas in the United States (as of December 31, 1970)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1971), p. 15.

Variable	Highest Supply I	II	III	Lowest Supply IV
	Cases Analyzed			
Drilling Rate	High Growth	Medium Growth	Medium Growth	Current Downtrend
Finding Rate	High	High	Low	Low
	North Slope Production Starts			
Oil	1976	1976	1976	1981
Gas	1978	1978	1978	1983

Other important variables, such as application of additional recovery techniques, leasing and operating expense factors, were handled in the same manner in all cases. The sensitivity of the results to these assumptions was tested and the findings are summarized later in this chapter.

Oil Reserve Additions

During the past 15 years, total crude oil reserve additions for the United States have averaged 3.3 billion barrels per year. The volume added to proved reserves as a result of new oil discoveries (exclusive of the 9.6 billion barrels added by the Alaskan North Slope discovery) has decreased from over 2 billion barrels in 1955 to about 1 billion barrels in 1970—a decline of more than 50 percent. Total reserve additions have been maintained only through greater application of increased recovery techniques to previously discovered reserves and the North Slope discovery. The lowest supply case investigated (Case IV) maintains total reserve additions at about 2.8 billion barrels per year for the next 15 years, largely as a result of continued application of increased recovery methods. The highest investigated supply case (Case I) adds reserves at an increasing rate—averaging 4.4 billion barrels annually. These projected volumes include reserve additions ranging from 0.3 to 0.6 billion barrels per year on the Alaskan North Slope.

Oil Production

Based on these reserve additions, crude oil production is projected to increase from the 1970 level of 9.1 MMB/D to levels between 9.4 MMB/D (Case IV) and 13.5 MMB/D (Case I) in 1985. Approximately 20 percent of this U.S. total, or 2 to 2.6 MMB/D, will come from the North Slope of Alaska. Equally important are the offshore regions which also provide about 20 percent of the 1985 production. Secondary and tertiary recovery processes account for approximately 40 percent of the 1985 crude oil production. Although the anticipated 1985 production rates are above the current level, *in all cases there was a period in which domestic oil production declined from 1970 levels at a rate of 2 to 3 percent per year for at least 5 years before beginning to increase.* This is a result of the lead time involved in finding and developing new production.

When condensate and gas plant liquids are added to crude oil, the resulting total petroleum liquids production rates in 1985 are projected to range from 10.4 to 15.5 MMB/D—compared to 11.3 MMB/D in 1970 as shown in the tabulation below.

TOTAL U.S. CONVENTIONAL LIQUID PETROLEUM PRODUCTION

	MMB/D			
	1970	1975	1980	1985
Case I	11.3	10.2	13.6	15.5
Case II	11.3	10.2	12.9	13.9
Case III	11.3	9.8	11.6	11.8
Case IV	11.3	9.6	8.9	10.4

The dependence on new discoveries and North production is shown on Figure 5.

Gas Reserve Additions

Annual gas reserve additions (non-associated and associated-dissolved) have averaged a little less than 18 TCF per year in the lower 48 states during the 1956-1970 period. Gas reserve additions in the past 3 years have been well below the average and were about 11 TCF in 1970. In addition, about 31 TCF of gas has been discovered in Alaska, of which 26 trillion was associated-dissolved gas found on the North Slope. In Case IV, total annual gas reserve additions are projected to decline further to an average of about 9 TCF in the next 15 years. In Case I, total annual reserve additions average approximately 27 TCF. These volumes include reserve additions ranging from about 1.3 to 4.2 TCF found annually in Alaska.

Gas Production

Wellhead gas production in the United States increased at an unprecedented rate in the decade of the 1960's from 13 TCF in 1960 to 22.3 TCF in 1970. A large backlog of proved reserves made this rapid increase in production possible; however, this reserve backlog has now been used up, and any subsequent increases in gas production will depend on future reserve additions.

In the highest supply case (Case I), gas production was projected to increase from 22.3 TCF in 1970 to 30.6 TCF in 1985, including 4.4 TCF from Alaska. The contribution from the offshore areas of the lower 48 states is 9.1 TCF in 1985. Thus, Alaska and the offshore areas make up close to one-half of the projected gas production in 1985 for the highest supply case.

In the lowest supply case (Case IV) gas production was projected to decrease to 15 TCF in 1985, with Alaska and the offshore areas providing a little over one-third of the total. Cases I-IV conventional gas production is summarized below.

TOTAL U.S. CONVENTIONAL GAS PRODUCTION

	TCF/Year			
	1970	1975	1980	1985
Case I	22.3	23.8	25.8	30.6
Case II	22.3	23.5	24.3	26.6
Case III	22.3	22.1	20.4	20.3
Case IV	22.3	21.7	17.3	14.9

The dependence on new discoveries and Alaska production is shown on Figure 6.

Capital Expenditures

The finding and development expenditures (in 1970 dollars) required to achieve these production rates for oil and gas are projected to grow from the average $5 billion per year level during the past 15 years to an average of $5.9 to $11.5 billion per year for the 1971-1985 period. These expenditures rise because of a shift to higher-cost frontier areas (offshore and Alaska), increased application of additional recovery methods and deeper drilling. These increased expenditures are coupled in most cases with an increase in activity levels and assume that the currently rising trend in offshore lease bonus payments will continue. Over the 15-year period the cumulative capital requirements for domestic oil and gas exploration and production would range from $88 to $172 billion.

Required "Prices" of Oil and Gas

Net fixed assets in the domestic exploration and production sector have been decreasing since 1968 as a result of insufficient new investments being attracted to the industry to offset the amortization of investments made in previous years. In order to achieve the supplies projected, this trend toward liquidation must be reversed. This can only be accomplished if the economic and political climate improves significantly compared to that which has prevailed during the last several years.

Average oil and gas required "prices" * needed to offset costs and to provide specified returns on net fixed assets were calculated for each of the supply cases. These returns are defined as the ratio of the annual net income after tax (before interest charges) to the average net fixed assets (average of beginning and end of year net investment property, plant and equipment). A broad range of reasonable returns was investigated as an alternative to making an arbitrary selection of a specific return level that would be required by an industry composed of numerous individuals and firms.

Return-on-net-fixed-asset type calculations were considered most appropriate for oil and gas because the base of assets and reserves built up in the past is very large and a minimum number of assumptions is required. This return on net fixed assets is not the same as return on shareholders' equity (also termed return on invested capital or on net worth). To calculate return on shareholders' equity for exploration/production operations alone would require a large number of additional assumptions with regard to such items as the working capital (inventories, cash, receivables and payables, etc.),

* These are calculated cost-plus-return prices only and do not represent selling prices established between producers and purchasers or a future market value.

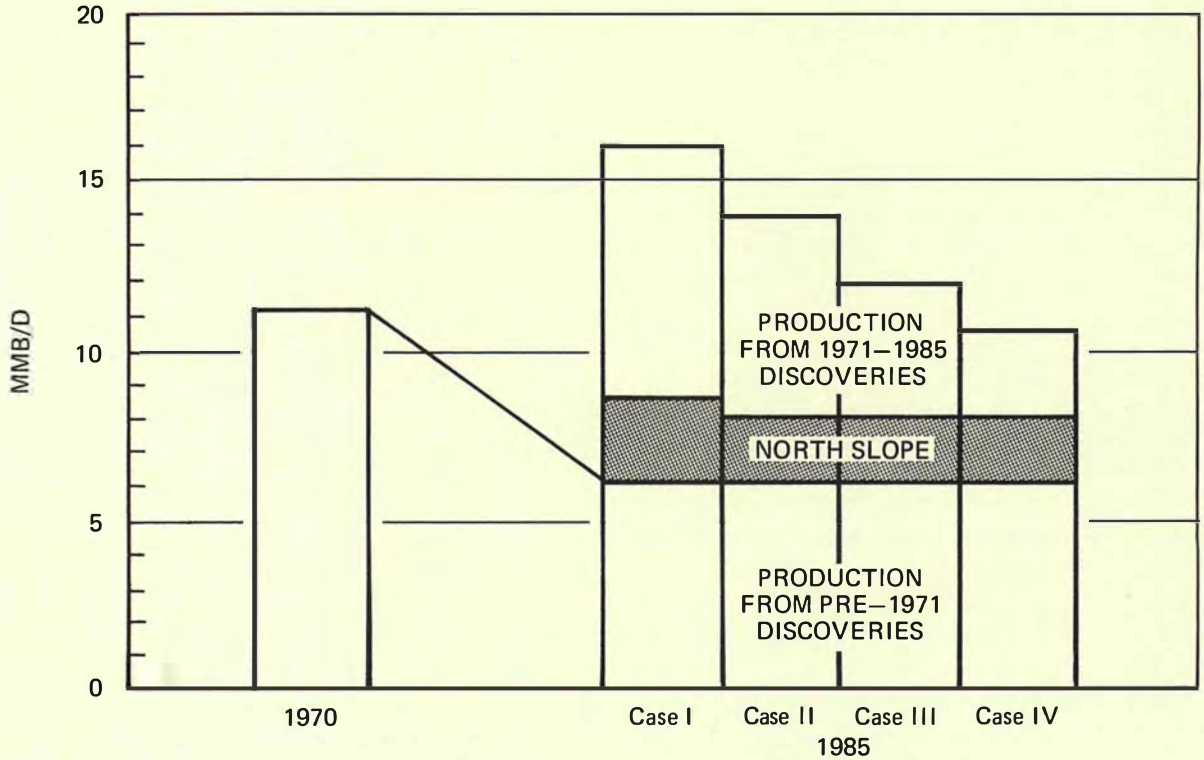


Figure 5. Total Petroleum Liquids Production.

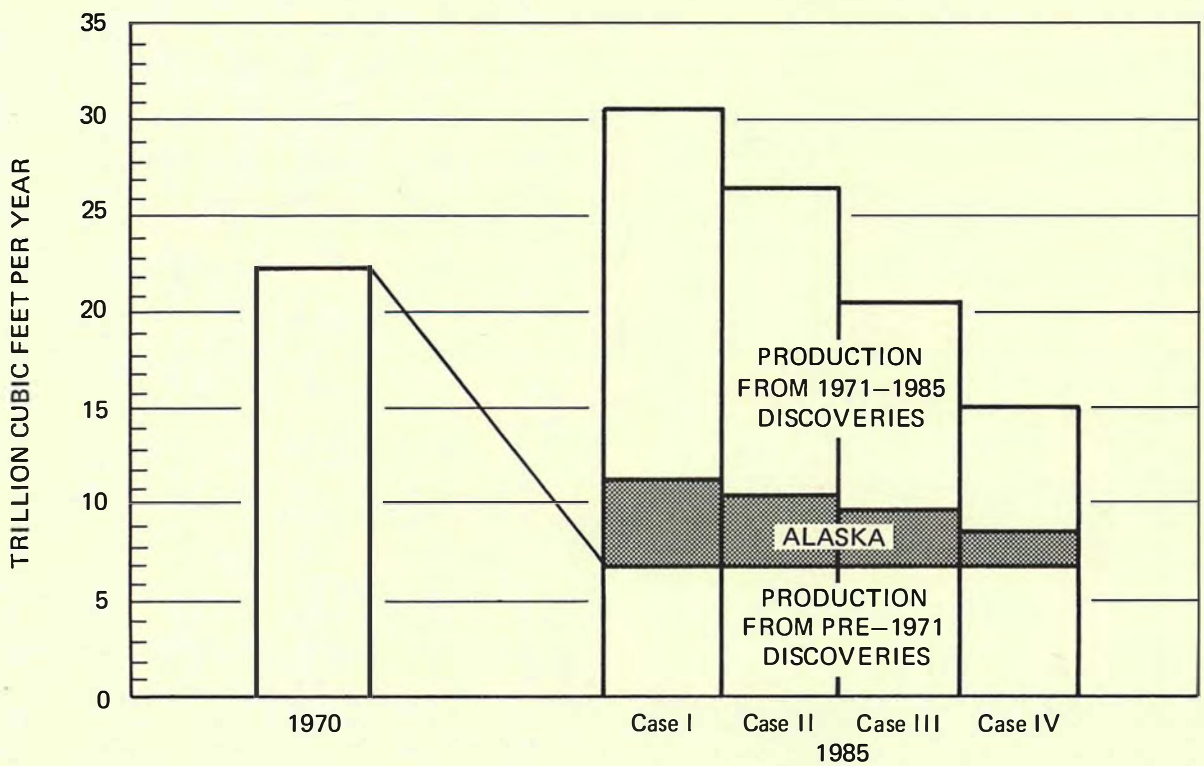


Figure 6. Total Natural Gas Production.

other long term assets (prepayments, deferred charges, goodwill, etc.) and long-term liabilities (principally debt). No historical industry data are available for estimating these items, and to attempt to do so would add additional uncertainty.

The cost calculations used do not include interest expense. It was considered inappropriate to attempt to determine the mix of debt and equity financing which could or should be achieved by the high risk exploration/production segment of the industry or to forecast interest rates over the 1971-1985 period.

Published estimates of historical returns on domestic exploration and production net fixed assets are available and provide a basis for comparison of projections with past performance.* These historical data on returns on net fixed assets generally parallel return on the shareholders' equity interest in the industry as a whole.

To examine the sensitivity of the return to the base used, an estimate of working capital was added to the asset base. Although no reliable published data are available on working capital assignable to only exploration/production activities, 20 percent of net fixed assets was considered to be a reasonable estimate. The addition of working capital at that level reduces the return by about one-sixth, so that a 15-percent return on net fixed assets would be about 12.5 percent on total capital employed.

The average required "prices," or cost-plus-return values, calculated are shown in Table 15 (in 1970 constant dollars) for a 15-percent return on net fixed assets which was the middle of the range selected. All Alaskan North Slope operations and South Alaskan non-associated gas operations were excluded in calculating these required "prices." The reasons for this exclusion are the unique logistical difficulties and high costs associated with transportation of production from these areas and the lack of experience under any similar operating conditions.

These required "prices" and production rates provide useful information about supply and price. However, they should not be construed as measures of supply-price elasticity. To determine such elasticity, it would be necessary to isolate the effect of price from all other motivational considerations implicit in the historical data on which the projections are based. These data reflect the influence of finding experience, technology, governmental policies and cost factors—none of which can be separated from price in the past nor will they necessarily be duplicated in the future. Changes in these factors are difficult to predict quantitatively, yet the response of supply to price changes is critically dependent on them. For example, the long lead times which characterize oil and gas industry operations tend to cause current supplies to be more reflective of *past expectations* about prices and other relevant factors than current price, thereby making meaningful elasticities that much more difficult to calculate. Similar problems arise in attempting to calculate incremental costs between cases.

The required "prices" calculated indicate a need for a sharp reversal of the declining real price trends that have been experienced for the last several years. Declining prices have reduced the attractiveness of this high-risk industry as is evidenced by the decline in both drilling effort and in reserve additions resulting from new exploration.

The price projections assumed in the Initial Appraisal would imply, based on the results of this subsequent work, that the rate of return on oil and gas net fixed assets would sink to a completely unacceptable level of less than 2 percent. Thus, the Initial Appraisal price assumptions were not viable, and price increases would be needed to attain even the supplies projected in that study.

The "prices" calculated based on a constant return on net fixed assets are average "prices" realized on all production from both previously found and newly discovered reserves. Although oil and gas required "prices" were not based on a discounted cash flow (DCF) rate of return because of the industry's large existing operations, it was possible to use the resulting "prices" to estimate the DCF return on newly discovered oil resulting from new investments. The new oil DCF return was calculated to be 6 percent on new investments based on the "prices" estimated for Case II assuming a 15-percent return on net fixed assets. While this 6-percent return is an average value and some investors will realize a higher return (some will realize less), it must be questioned whether

* Kenneth E. Hill, "Financing the Petroleum Industry During the 1970's," paper presented at the API Division of Finance and Accounting Midyear Meeting, June 12, 1970, in Dallas, Texas.

TABLE 15

AVERAGE REQUIRED "PRICES" FOR OIL AND GAS—1970 CONSTANT DOLLARS
($/bbl or ¢/MCF)

	Actual*		Projected at 15% Return on Net Fixed Assets		
	1965	1970	1975	1980	1985
			High Finding Rates		
Crude Oil "Price" ($/bbl)					
Case I	3.26	3.18	3.65	4.90	6.69
Case II	3.26	3.18	3.63	4.73	6.18
Gas Field "Price" (¢/MCF)					
Case I	17.8	17.1	26.7	33.7	43.6
Case II	17.8	17.1	26.2	31.8	39.8
			Low Finding Rates		
Crude Oil "Price" ($/bbl)					
Case III	3.26	3.18	3.67	4.95	6.60
Case IV	3.26	3.18	3.57	4.39	5.28
Gas Field "Price" (¢/MCF)					
Case III	17.8	17.1	27.9	37.8	53.0
Case IV	17.8	17.1	26.6	31.6	38.7

* Bureau of Mines' actual data, unadjusted for rate of return.

such a return is high enough to attract the needed risk capital.

Gas "prices" present a special problem as a result of the vintaged ceiling price system imposed by federal regulation as well as long-term contractual obligations. If prices for previously contracted gas are not allowed by restriction to increase, the required "prices" for newly discovered gas would be substantially higher than these average values. For example, in one of the intermediate cases (Case III), the computed 15-percent return average "price" in 1985 is $0.53 per MCF. However, if prices for gas discovered prior to 1971 are held at current levels, the gas supply discovered in the projection period will require a corresponding unit "price" in excess of $0.75 per MCF.

Parametric Studies

The exploration and production segment of the industry has been in a phase of decreasing activity and liquidation of assets for a period of several years. Strong incentives are needed to encourage the industry to reverse this trend and increase its activity at the rates required to generate the higher supplies projected. Not only will immediate incentives be required to improve the domestic oil and gas supply situation, but because of the long lead times required to find new fields and initiate production from them, the *expectation* of a stable and satisfactory economic and political climate will be necessary.

In this study, the effects of variations in assumptions for major factors—or parameters—that influence oil and gas finding, development, production and related economics were examined. The most significant of these parametric studies were those dealing with finding rates, offshore leasing, taxation policy and the acceleration of additional-recovery activity. Some examples of the relative magnitude of the impact of changes in some of these variables are discussed in the following paragraphs.

Experiencing a different finding rate than projected would have a sizable impact on volumes and "prices." If, in the intermediate drilling case, a high rather than a low finding rate were experienced (Case II *vs.* Case III), the 1985 liquid production realized would be increased by 2.1 MMB/D and marketed gas production by 5.1 TCF/year. Also, the 1985 "prices" required to maintain a 15-percent return on fixed assets would be reduced by 42¢/bbl of oil and 13.2¢/MCF of gas, respectively.

The rate of application of secondary and tertiary recovery processes in Cases I-IV is consistent with the historic increase in oil-recovery efficiency. If, because of increased economic incentives or a technological improvement, additional-recovery projects were implemented at a 50-percent greater rate in the highest supply case, the following could result: oil production would be increased by 2.0 MMB/D in 1980 and 1.8 MMB/D in 1985; the required price increase to pay for this activity would be 71¢/bbl in 1980 and 51¢/bbl in 1985.

The application of nuclear-explosive technology to fracture very low-permeability natural gas reservoirs could result in production approaching 1 TCF per year by 1985. The most significant aspect of this technology is that its utilization is intended primarily in reservoirs where conventional well-completion techniques would not result in sufficient production to warrant development. Possible utilization of nuclear-explosive fracturing technology is dependent upon certain refinements in nuclear-explosive hardware design, legislation permitting nuclear explosives to be used for such commercial applications, regulatory procedures to permit marketing gas containing small amounts of man-made radioactivity, and public acceptance of such practices.

If no new leases were offered in the offshore areas by the Federal Government, projected production would be lowered by over 2 MMB/D of domestic crude oil and nearly 6 TCF/year of gas in 1985. If, in addition, the North Slope oil were enjoined from being brought to market before 1985, at least another 2 MMB/D of production would be lost. If a pipeline outlet is not developed for North Slope gas, approximately 2.7 TCF annually of natural gas would be denied the lower 48 states markets.

Nearly $1 billion was spent in 1970 for offshore leases under the sealed, cash-bonus-payment system currently used. This system adds to the cost of petroleum products by diverting capital from exploration and development activity into transfer payments to the Government. In the absence of bonus payments, average U.S. "prices" required for a 15-percent return in 1985 would be reduced by $1.14/bbl for oil and $0.09/MCF for gas (Case II). Other systems of awarding leases, including the work program approach used by Great Britain and royalty bidding, have been examined. These two alternatives would reduce industry's initial cash outlay for leases and thereby provide additional cash for exploration and development. Although it cannot be demonstrated that the current bonus payment system is economically advantageous, the political reality of changing such a long-established system would be difficult. The main drawback to royalty bidding is deciding which bid is the "highest," and the possibility that producing properties would become economically unattractive to operate and be abandoned at an earlier date than with bonus payments and lower royalties.

It is essential that acreage be made available in the offshore areas where finding rates are expected to be high. The intermediate drilling cases (Cases II and III) will require 21 million acres to be made available during the 15-year period studied. This compares to 7 million acres actually leased since 1954. Without this acreage, the supplies projected would not be found. In addition, an intensified effort would not be made to develop the technology required to find and produce the resources anticipated to be in areas such as the deep offshore and the Arctic shelf. Acreage must be leased in large enough parcels to assure the risk-taking operator that there is a fair chance of obtaining production that will pay for such costly efforts. The possibility that there could exist some extremely large fields in these virgin areas capable of making major contributions to supply further emphasizes the desirability of making these areas available.

Many changes in tax regulations are possible. The most important item is the statutory depletion allowance. If this provision were completely removed, required "prices" would have to increase over projected levels by about $0.50/barrel and $0.03/MCF immediately and by approximately $0.90-$1.00/barrel and $0.05-$0.07/MCF in 1985 to provide the same incentives for oil and gas exploration and development investments. Elimination of the depletion allowance would have an even greater impact on high tax bracket investors who are a very important source of funds for many of the independent producers who play a significant role in discovering new fields. An investor who pays taxes at a 70-percent marginal rate would require increases over required "prices" of $1.20/barrel and $0.07/MCF immediately and $2.51/barrel and $0.17/MCF in 1985, compared to the figures quoted above for a corporate taxpayer.

Because depletion is limited to 50 percent of net income, an increase in the statutory depletion allowance to 35 percent would provide the same effective depletion (27.5 percent) originally intended by Congress. This would allow the 1985 "prices" to be about $0.50/bbl and $0.03-$0.04/MCF lower than projected in the base cases at comparable return on investment levels.

Another tax policy option examined is a requirement to capitalize intangible drilling costs for tax purposes in lieu of the current option to expense these costs. This would immediately reduce the after-tax capital available for drilling by over $800 million per year. While this effect on industry earnings diminishes in later years as a depreciable base is built up, any new investor will always bear the full impact since he has no depreciable base with which to start. Although the resulting negative impact on reserve additions and domestic production of oil and gas cannot be calculated with the methodology, the effect could be major.

A number of other parametric studies were analyzed. The results are presented in the full report.

Oil and Gas Logistics

Additional transportation and logistical facilities will be needed. The type and location of the facilities to move, store and process energy fuels will vary depending on the availability of domestic energy supplies, the type and volumes of imports and government policies and regulations. This section summarizes expected transportation and logistical developments in the 1971-1985 period under the intermediate demand Cases II and III supply conditions.

Oil

The activities, operations and results obtained in Cases II and III for the period 1971-1985 have many implications.

- As demand for refined petroleum products increases, additional petroleum refining capacity will be required. The growth of refinery capacity in the United States will be dependent on U.S. import policies, comparative economics and a resolution of environmental problems. National policies which favor importation of residual fuel oil and other petroleum products and semi-refined oils would result in refining capacity being built abroad rather than in the United States.
- Economic and environmental considerations favor the use of very large tankships of 250,000 to 400,000 DWT for oil movements. At the present time, however, there are no U.S. ports capable of handling vessels of this size. Offshore terminals must be built on the Gulf, East and Pacific Coasts if the benefits of very large crude carriers (VLCC's) are to be gained.
- Crude oil imports into the U.S. Gulf Coast will expand both for use in coastal refineries and for transshipment inland. Large-diameter pipelines and increases in waterborne commerce may be needed into the interior from the East Coast and/or the Gulf Coast. Coastwise shipping patterns may be altered. Volumes will be controlled by the relative refinery capacity existing in each area.
- In Case III, the capital costs for refineries and logistical facilities necessary to accommodate U.S. oil requirements between 1971 and 1985 could be in the neighborhood of $50 billion (in 1970 dollars).

Gas

The supply/demand balances for Cases II and III during the 1971-1985 period indicate total U.S. gas demand, absent supply limitations, would increase from 22 TCF per year in 1970 to more than 41 TCF in 1985. Domestic gas production, including Alaska, is projected to range from 20.4 TCF (Case III) to 26.5 TCF (Case II) in 1985 compared with about 22 TCF in 1970. These basic developments in U.S. gas supply and demand have the following implications.

- The probable location of post-1971 gas discoveries in the lower 48 states and offshore areas will require construction of new gathering, feeder and transmission-line facilities even though total supply may not increase. Gas volumes projected to be available from Alaska and Canadian frontier areas under Case II expectations would require construction of about 10,000 miles of 48-inch pipeline by 1984, assuming 75 percent of such new production is destined for U.S. markets.
- Maximum-sized LNG tankers are projected to

have a capacity of some 160,000 cubic meters, or approximately 1 million barrels. Liquefaction-plant capacity is likely to be based on a modular concept approach with 150 million cubic feet per day (MMCF/D) used as the most efficient-sized unit.

- Although LPG supplies from conventional sources in the lower 48 states are expected to increase modestly through 1975 and decrease thereafter, increases in supply are projected from: (a) the North Slope of Alaska and Canada, transported in vapor form in the gas pipeline; (b) LPG pipeline imports from Canada; and (c) LPG tanker imports from South America, Africa and the Mideast.
- Capital expenditures for gas pipelines, LNG imports and LPG supply, including all appropriate and related physical facilities, are projected to be about $40 billion in Case III for the 1971-1985 period, and more than $56 billion in Case I for the same period.

Findings—Coal

The Nation has abundant resources of coal. With the further development and application of technologies for (a) solving the environmental problems inherent in the mining and combustion of coal and (b) transforming solid coal into synthetic gaseous and liquid fuels, U.S. coal resources can make a major contribution to the Nation's future energy needs. The ultimate size of this contribution will depend primarily on the outcome of government policy issues.

Resource Base

Approximately 150 billion tons of recoverable coal—45 billion located near the surface and 105 billion located more deeply underground—exist in formations of comparable thickness and depth to those being mined by present technology. This reserve position will support production through 1985 from the same type of deposits currently being mined, even at the maximum production growth rate considered feasible (5 percent per year for the conventional domestic market, 6.7 percent when production for export and for synthetic markets is included). Maximum projected production to 1985 will require less than 10 percent of this 150 billion tons.

The 150 billion tons represent less than 5 percent of the total coal resources—3.2 trillion tons—estimated by the U.S. Geological Survey to be available in the United States. Further exploration and mapping of the Nation's coal reources should result in substantial additions of reserves minable with present day technology. This is especially so in the western states where large coal bearing formations have been only partially explored.

Improved mining technology could also increase recoverable coal reserves, but the development of this technology requires a long lead time and is costly. Current research efforts are insufficient.

Future Coal Supply and Utilization

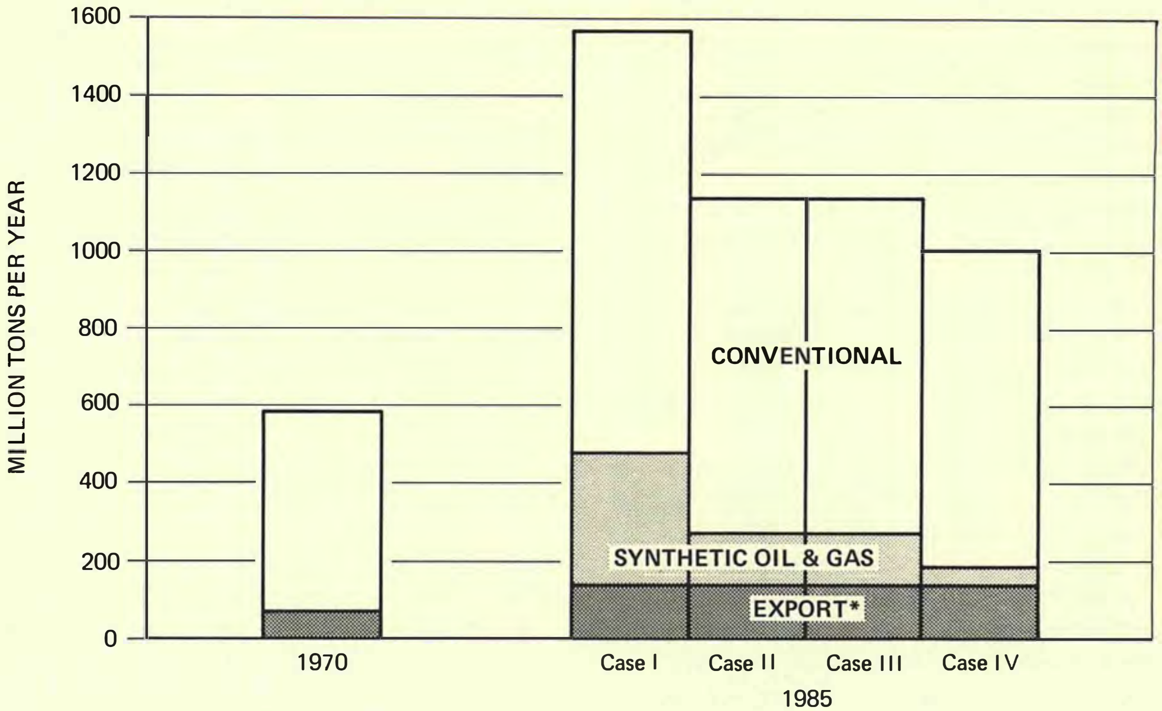
Table 16 and Figure 7 summarize the projections for supply and use of domestic coal under Cases I-IV.

TABLE 16
PROJECTIONS FOR SUPPLY OF DOMESTIC COAL

	Millions of Tons per Year 1970	Millions of Tons per Year 1985	Percent Growth Rate
Case I:			
Conventional markets	519	1,093	5.0
Export	71	138	4.5
Synthetic fuels	0	339	–
Total Case I	**590**	**1,570**	**6.7**
Case II/III:			
Conventional markets	519	863	3.5
Export	71	138	4.5
Synthetic fuels	0	133	–
Total Case II/III	**590**	**1,134**	**4.5**
Case IV:			
Conventional markets	519	819	3.0
Export	71	138	4.5
Synthetic fuels	0	47	–
Total Case IV	**590**	**1,004**	**3.6**

Some of the key factors that will affect the ability of the coal industry to achieve the above rates of growth are as follows:

- Utilization of coal as a boiler fuel in conventional markets depends on future air quality standards. Over 40 percent of estimated coal resources east of the Mississippi River have a high sulfur content (over 3 percent). Case I assumes that technology for economic stack gas cleanup will be developed early in the



* *For purposes of this study, coal exports were held at the Initial Appraisal levels for all four cases.*

Figure 7. Projected U.S. Coal Production

1971-1985 period, making possible the continued use of higher sulfur levels of coal. Cases II-IV are premised on somewhat less success in solving the problems that are retarding coal's usage. It is important to the use of coal that future government air quality regulations be adopted on a timetable which will improve environmental quality without disrupting the supply of this needed energy resource.

- Utilization of coal for synthetic pipeline gas is projected to supply 2.48 TCF per year in 1985 under Case I, 1.31 TCF per year under Cases II/III and 0.54 TCF per year under Case IV. Technology for the production of low-BTU gas from coal is available today, and the technology for producing higher BTU gas is being rigorously pursued. Conversely, technology for economically producing coal-based liquids is not available today. Maximum projected output of coal-based liquids is 680 MB/D under Case I. To approach such a level of production would require an immediate decision to proceed with the design and construction of a first demonstration liquefaction plant. This would be a high-risk plant because technology is now only partially developed. (Under current economic conditions, the incentives to develop and build such a plant do not exist.)
- Domestic coal reserves are more than adequate to support synthetic fuel plants in addition to meeting a growing demand for conventional coal uses. But the projected building rates for synthetic plants are dependent on water availability as well as coal availability. Achievement of synthetic fuel production will require (a) massive government expenditures to provide the necessary water for mine-mouth synthetic plants in the relatively water deficient western states, as well as (b) coordinated action by governmental bodies to ensure the legal availability of this water.
- Banning of surface mining will reduce Case I production by approximately one-half in 1985 and will essentially eliminate production for synthetic liquids and gas. The banning of surface mining and consequent restriction of

energy from this source would not be required if reasonable land reclamation regulations are enacted.

- Since the Federal Government owns a large percentage of the coal bearing lands, federal leasing policy will have a strong influence on production of synthetics from western surface-minable coal. Coal conversion will require the availability of large blocks of reserves to justify the large required plant investments. Unitization of public land coal leases should be permitted, and bonus and rental payment requirements should be designed to encourage development.
- The extent to which coal transportation facilities can be improved will have an important effect on future growth in coal usage. The transport of coal to market depends heavily on rail transportation and water transportation. In the case of the railroads, introduction of the unit train concept has increased efficiency of car utilization, but a critical shortage of hopper cars still exists, and will for the foreseeable future without a massive increase in new investment. Water transport of coal is attractive because of its low cost. But there is a pressing need to modernize and enlarge the Nation's navigation system. Barge traffic is already exceeding the economic capacity of certain key waterways, and this situation may worsen in future years.
- To achieve the projected coal production and transportation of coal to market, the cumulative capital requirement over the 1971-1985 period is estimated to be—

Coal Industry	$9.4 to $14.3 billion
Transportation Industry	$ 6.0 billion

- Attraction of adequate numbers of capable young workers into mining has been a problem and may become a greater one because of increasing use of sophisticated equipment requiring a higher level of worker competence. More serious as a potential problem, however, is the possible shortage of certain specifically trained supervisory and professional manpower.

Cost Outlook

Future mining costs have been estimated for both surface and underground coal. Resulting required "prices" for coal needed to cover costs and provide specified DCF rates of return have been calculated.

The DCF mathematical procedure of calculating rates of return on capital investments is a method of economic analysis particularly useful for analyzing investment projects that are capital intensive and that have long development periods (capital expenditures) prior to receiving any return of cash. This method considers the time value of money and the earning power of individual investments.

This method consists of scheduling the actual cash flow from an investment project over its entire life; the cash flow will typically be negative during the initial investment period and positive during the subsequent revenue generating period. The time value is considered by discounting the cash flow stream to the equivalent initial period value using compound interest factors. The factor at which the cash income stream is discounted to exactly equal the discounted investment stream is defined as the DCF rate of return.

To make these calculations, it is necessary to make assumptions regarding the life of the project, rates of expenditures of cash for capital investments, rates of cash return, and rates of operating costs, as well as the usual assumptions required for any method of computing rates of return. The results of these calculations shown in this report are average "prices" required for various DCF rates of return over the life of the projects.

The coal report uses the DCF method for calculating rates of return for various price levels of coal produced from the eastern, midwestern and western regions of the United States, making the required assumptions that are consistent with the practices in the coal mining industry. Little data have been published in regard to the average capital and operating costs of producing coal. For coal produced from the eastern and midwestern regions, two hypothetical coal mines—one surface and one underground mine—were developed to serve as a basis for the economic model. The required assumptions were made and used to design each mine in such a manner that they reflected the average operating conditions which existed in the coal industry during a base year (1969). DCF rate of return calculations were made for the average coal production (from old mines plus new mines) and also for coal production from new mines. In order to determine the range of "prices" versus

DCF rates of return for coal produced by surface mining from the western region, a typical surface (area) mine was defined, and the "prices" of coal were calculated as a function of overburden to coal ratio.

In terms of constant 1970 dollars, the results may be summarized as follows:

- For underground and surface production in the eastern and midwestern United States, both of which are oriented toward conventional coal uses (and for export), the "price" of coal will continue to vary widely by region due to the great variance in regional mining conditions. The "price" of coal from underground mines in 1985 will range from a regional average of about $6.50 per ton to a regional average of about $14.50 per ton from the lowest cost to the highest cost region, assuming a DCF rate of return of 15 percent. The corresponding range for surface production in 1985 is somewhat narrower—$5.50 to $9.90 per ton. These "prices" represent a mix of production from existing mines and projected new mines. Because of the greater investment required to open a new mine, a projection of required "price" for coal produced only from new mines would be higher.
- The cost to mine underground coal has risen sharply in recent years, as productivity has been lowered by new mine health and safety regulations. Barring unforeseen developments, future underground mining costs should increase more slowly because productivity is expected to resume its historical upward trend. The cumulative effect is to increase the average "price" of coal from underground mines to $9.60 per ton in 1985, including a 15-percent DCF rate of return, for a rise of about 30 percent over the period.
- The constant dollar cost of eastern and midwestern surface-mined coal will rise by about 30 percent by 1985, due to increased reclamation costs and an increasing average overburden ratio. This increase will result in the average "price" of coal increasing from about $5.30 per ton at the beginning of the period to $6.80 per ton in 1985, including a 15-percent DCF rate of return.
- Coal to be used in the production of synthetic gas and liquid fuels is assumed to come largely from western coal fields. However, it is recognized that synthetics may be produced in limited quantities in other areas. Future costs for mining western coal are uncertain but are estimated to fall within a range of about $2.75 to $4.00 per ton, including a 15-percent DCF rate of return. It is this relatively low cost that will make western surface-mined coal attractive for synthetic production.

The economics of producing syngas from coal were first calculated by developing a typical coal gasification plant (size, process, configuration, etc.) and making the necessary assumptions of capital expenditures, cost of coal and other operating costs. With these assumptions and an assumed charge against the rate base as used in utilities, the required "price" for syngas was calculated. Under these identical conditions, a standard DCF rate of return calculation was made, assuming a 15-percent rate of return and calculating the required "price" for syngas.

Depending upon the cost of coal, the resulting "price" of synthetic gas has been estimated to be $0.90-$1.10 per million BTU's in constant 1970 dollars at the plant site, based upon an 18-percent charge against the rate base. On the basis of a 15-percent DCF rate of return on investment, however, the "price" from the lowest cost coal would be approximately $1.20 per million BTU's.

The economics of producing syncrude from coal were calculated in the same manner as those for producing syngas, using a typical coal liquefaction plant. With these assumptions and assuming a DCF rate of return, the required "price" for syncrude under these conditions was calculated. For a 30 MB/D commercial demonstration plant, the "price" of synthetic liquids produced from western coal has been estimated to range from $6.25 to $6.75/bbl at the plant site in constant 1970 dollars, at a 10-percent DCF rate of return on plant investment and to range from $7.75 to $8.25/bbl at a 15-percent rate of return. For a 100 MB/D plant, these "prices" may drop by some $0.50/bbl.

Findings—Nuclear

Nuclear energy consumption in the United States is expected to increase from about 5 percent of the total energy used to generate electricity in 1972 to about 40 percent in 1985. A national effort to achieve full utilization of the potential for nuclear power generation could result in even greater consumption of nuclear energy by 1985. It is expected that the uranium industry can discover and develop the required domestic uranium reserves to fuel this power generation if the necessary exploratory effort is undertaken. However, to provide even the expected level of nuclear power generation and to ensure an adequate fuel supply from domestic sources, it is necessary that—

- The Government promptly establish nuclear power plant siting and licensing procedures to expedite the issuance of construction and operating licenses
- Adequate economic incentives prevail to encourage the uranium industry to undertake the task of achieving the level of exploration and mine/mill construction needed now to assure future supply
- The present government policy regarding importation of foreign uranium be continued.

Resource Base

The AEC currently estimates proved plus potential uranium resources to be roughly 700,000 tons minable at a cost up to \$8/lb U_3O_8 and 1.6 million tons minable at a cost up to \$15/lb U_3O_8.* Also, the resource base in the United States offers the prospect of locating significant additional reserves.

About 95 percent of known uranium reserves are located in sedimentary basins of the western United States. A large percentage of these basins and other basin areas in the United States favorable for uranium deposition have not been adequately explored. Given the extensive, relatively unexplored areas of the United States that are favorable for uranium, there is reason to believe that additional minable uranium deposits will be discovered.

Proved reserves can supply the demand through 1980, although new mining and milling facilities will be needed to produce some of these deposits. Proved and potential domestic uranium resources minable at a reasonable cost can be available to provide the expected fuel requirements of nuclear power plants through 1985. However, to assure supply after 1980, an exploration program must be initiated in the near future to convert potential uranium resources to minable reserves and to discover new ore bodies not included in present uranium resource estimates. Assurance that present government policy regarding importation of foreign uranium will continue is essential if the necessary investments are to be made.

The long lead time needed for uranium exploration and development of reserves requires a rapid increase in exploration activity over the next 5 to 6 years. Surface drilling, which historically has been a good measure of uranium exploration activity, should increase from 15.5 million feet in 1971 to 45 million feet in 1977 to provide the reserve additions necessary to meet Case III demand, and

DOMESTIC RESOURCES OF URANIUM(1)
(As estimated by the Atomic Energy Commission)

COST OF PRODUCTION (Per Pound)	REASONABLY ASSURED (Proved Reserves)	ESTIMATED ADDITIONAL (Potential Reserves)	TOTAL
\$ 8 (or less)	273,000	460,000	733,000
\$15 (or less)	625,000 (2)	1,000,000	1,625,000

(1) As of January 1, 1972.
(2) Includes 90,000 tons potentially recoverable as a by-product of phosphate and copper mining.

* As used here, potential resources refers to uranium estimated to occur in unexplored extensions of known deposits or in undiscovered deposits in known uranium districts and which is expected by the AEC to be discoverable and exploitable in the given range. The "price" calculations of this study appear in the subsequent text.

to 65 million feet in 1977 to meet Case I demand. This rate of surface drilling presupposes that the recently experienced uranium finding rate of about 4 pounds of U_3O_8 per foot drilled will continue. If the finding rate should decline, drilling requirements would be greater.

The ability of the industry to conduct uranium exploration programs of the magnitude required depends upon access to lands having uranium discovery potential in the western United States. Since about 50 percent of all proved and presently identified potential uranium resources are on federal or Indian lands, these lands must remain available for exploration, development and production.

In addition to uranium, thorium is a naturally occurring element that can be utilized as part of the nuclear fuel in high-temperature gas-cooled reactors. Thorium resources are known to exist in this country in significant quantities, and the quantity required through 1985 is not expected to be large.

Nuclear Power Growth

Nuclear power growth establishes the basic demand for nuclear fuels. In the Initial Appraisal, installed nuclear generating capacity was projected to increase from 7,000 MWe (megawatts of electrical generating capacity) in 1970 to 300,000 MWe in 1985. Depending largely on the degree to which nuclear power plant siting and licensing procedures will be improved so that plants can be built and operated on a timely basis, installed nuclear capacity could range from 240,000 MWe to 450,000 MWe in 1985 as projected in this study. The nuclear power capacity projections used in this report are summarized below and on Figure 8.

Case III corresponds closely with current forecasts of nuclear power generating capacity by both the AEC and FPC, as well as the projections in the Initial Appraisal. Case IV allows for a continuation and worsening of delays in nuclear power plant installation caused by licensing requirements and procedures and by objections raised in the courts under the environmental protection laws. Conversely, Case II assumes that standardization of licensing procedures and provision for realistic environmental protection criteria for design will enable timely approval of construction and operating licenses. Case I projects a very high level of nuclear power capacity that is attainable, but only with an immediate, concerted effort by both Government and industry to make utilization of the full potential of nuclear energy a high-priority national goal.

PROJECTED NUCLEAR POWER GENERATING CAPACITY
(Thousand Megawatts)

	Case			
	I	II	III	IV
1975	64	64	64	28
1980	188	188	150	107
1985	450	375	300	240

In each of the four cases, nuclear power plants projected to come into operation through 1985 are assumed to be light-water or high-temperature gas reactor plants, which utilize uranium for fuel. After 1985, it was assumed that the breeder reactor, a new type of nuclear reactor that requires much less uranium fuel, will provide an increasing share of nuclear power generation. The sharp growth in demand for uranium raw material and enrichment services expected during the late 1970's and early 1980's will level off after 1985 as breeder reactors become operable.

Uranium Requirements

The four nuclear power growth cases will require cumulative uranium production through 1985 ranging from 400,000 tons of U_3O_8 in Case IV to 700,000 tons in Case I. Projected uranium requirements in all four cases are shown below.

Uranium Supply and Nuclear Fuel Processing

Uranium mining and milling capacity now in operation or under construction plus the existing U_3O_8 inventory held by industry are adequate to meet U.S. requirements at least through 1975 under all demand cases considered. Additional mining and associated milling facilities that can be supported by presently proved reserves will need to come into operation in 1976. Because of the lead time required for mine development, investment in these new facilities should commence immediately if adequate production capacity is to

URANIUM REQUIREMENTS FROM INDUSTRY (Thousand Tons U_3O_8)								
	Case I		Case II		Case III		Case IV	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975	19	58	19	58	19	58	12	31
1980	51	240	46	230	37	200	29	140
1985	109	700	89	600	71	500	60	400

be available. Commitments to construct new mills must be made beginning within 1 or 2 years in order to meet projected requirements through 1980.

The nuclear report uses the DCF method for calculating several rates of return for various price levels of uranium oxide (yellow cake) produced from future mine and mill facilities, making the necessary assumptions that are consistent with the practices of the uranium producing industry. The unique assumptions over those required for oil shale and coal are those relating to the exploration activities necessary for the uranium industry.

There are no published net-fixed-asset data for the uranium producing industry. The operating and capital cost data used were basically those provided by the AEC.

In constant 1970 dollars, the calculated average "price" of U_3O_8 produced from new mines and

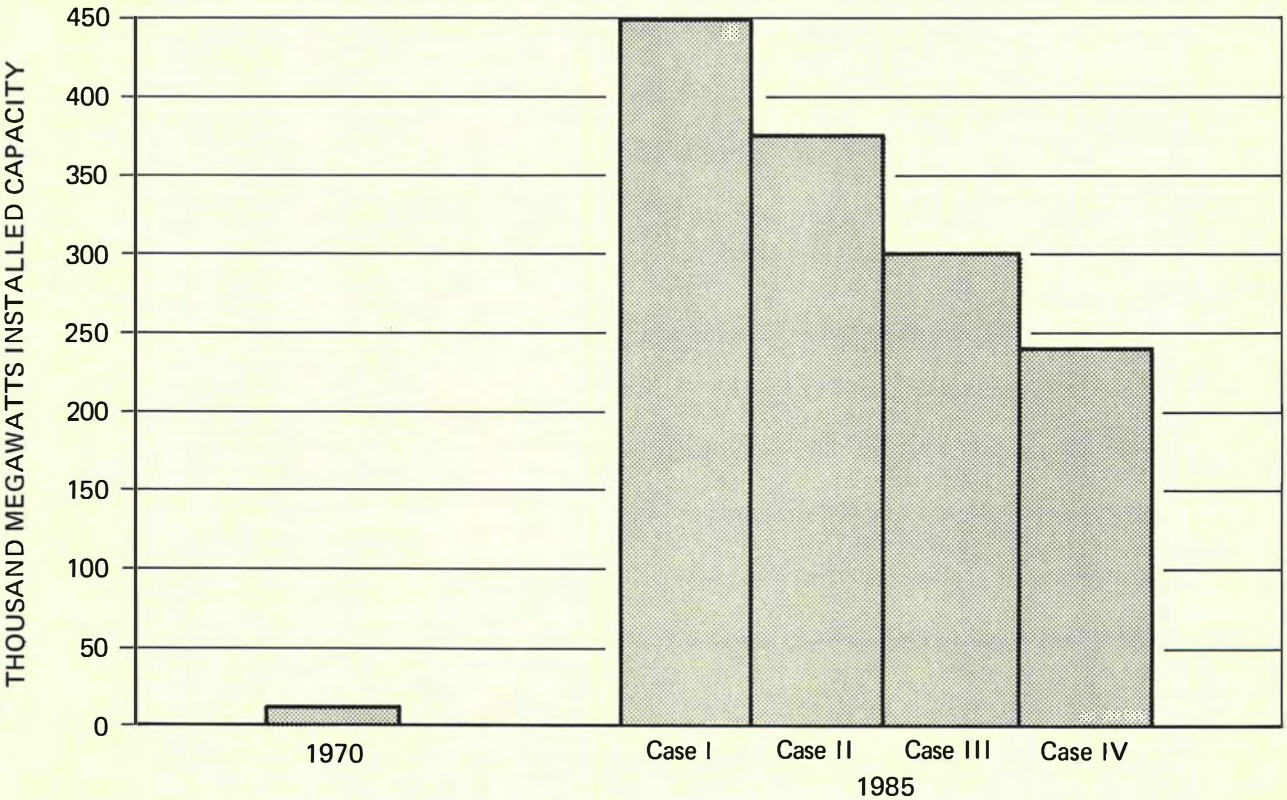


Figure 8. Projected Availability of Nuclear Generating Capacity.

mills that will come into production between 1976 and 1985 is \$10.50 per pound of U_3O_8 to provide a 15-percent average DCF rate of return on investment.* Considering the risk inherent in exploration ventures, the individual supplier may or may not find that a 15-percent return on investment in exploration, mining and milling is sufficient to justify the effort required to find the necessary uranium reserves and bring them into production. Present market conditions have not attracted the investments necessary to explore extensively for additional uranium deposits or to develop many known properties.

Although the need for an increase over present price levels is apparent, it should be noted that the cost of electricity from nuclear power plants is less sensitive to increased fuel costs than the cost of electricity from fossil-fuel plants. An increase of \$1.00 per pound in the price of U_3O_8 increases the cost of generated electricity by about 1 percent.

Uranium exploration and production of uranium concentrates are only the first of several steps in nuclear fuel production and processing. Subsequent processing steps, which form the balance of what is commonly called the nuclear fuel cycle, include converting uranium concentrates to uranium hexafluoride (UF_6), enriching the UF_6 to increase the proportion of the uranium isotope U_{235} in the material, manufacturing and fabricating the enriched material into a form suitable for use as fuel in a nuclear reactor, and finally, reprocessing the spent fuel to recover plutonium and "unburned" uranium. Of these steps, enrichment as well as uranium production capacity need the most immediate attention.

The U.S. Government owns and operates three uranium enrichment plants which have a combined capacity of approximately 17,000 metric tons of separative work per year. Present plans call for expanding the capacity of these enrichments plants to about 28,000 metric tons per year and to preproduce enriched uranium over the next several years while enrichment capability is greater than requirements.

To gain additional enrichment capacity, the AEC recently announced plants to change the method of operating the enrichment plants to recover less of the U_{235} isotope. This new operating plan will, however, require an increase in uranium feed, which will be supplied from the Government's uranium stockpile.

Despite the various plans to extend capacity, a new (fourth) enrichment facility will be needed by 1982 to meet the requirements of Case III and by 1980 to meet the requirements of Case I. A decision is needed promptly as to whether the Government or private industry will build the new enrichment plant. The urgency for obtaining this decision derives from the long lead times for planning, designing and building, large capital investments and advanced technology associated with these facilities.

Surplus capacity currently exists in all segments of the uranium fuel cycle including uranium production, conversion to UF_6, enrichment, fuel fabrication and spent fuel reprocessing. However, in order to match nuclear fuel production and processing capacity with future market demands, an aggregate capital investment ranging from \$6.7 billion (Case IV) to \$13.1 billion (Case I) will be required for the period 1971-1985. The orderly construction of these new facilities by private industry will, to a large extent, depend on timely government regulatory action.

Findings—Oil Shale

Oil shale is processed into crude shale oil, then semi-refined into what is called syncrude. The syncrude product is a 46° API hydrotreated distillate, essentially free of sulfur and low in nitrogen, thus constituting a premium refinery feedstock.

Although oil shale deposits are extensive, supply from this fuel source is expected to make only a minor contribution to U.S. energy supply by 1985.

Resource Base

Oil shale deposits are located in several areas of the United States, but only one region—the Green River Formation in Colorado, Utah and Wyoming—is considered to be of adequate size and availability to be commercially attractive. Estimated minable U.S. oil shale reserves are located in the Piceance Basin of Colorado and the Uinta Basin of Utah of the Green River Formation. Selected tracts with recoverable reserves of 54 billion barrels of syncrude were examined closely as the most economically recoverable of the huge 1,781 billion barrel resource estimated to exist in the Green River Formation. Of this vast resource

* Based on estimated average costs and a uranium finding rate of 4 pounds U_3O_8 per foot of drilling.

base, 129 billion barrels are in zones that contain over 30 gallons per ton of shale in seams exceeding 30 feet of thickness. In Case I, less than 6 billion of the 54 billion barrels of the most economically recoverable reserves, all located in the Mahogany Zone of the Piceance Basin, are projected for development through 1985.

Future Supply Potential

Under favorable conditions but short of an all-out national effort, projected maximum syncrude production capacity (Case I) is estimated by 1985 to be 750 MB/D. This output would require an estimated capital investment in plants of $4.0 billion. Lower projections (Cases II-IV) reflect slower rates of investment because of either the lack of investment incentive or the need for time to demonstrate process feasibility.

	Production of Syncrude from Oil Shale—MB/D		
	1975	1980	1985
Case I	0	150	750
Case II/III	0	100	400
Case IV	0	0	100

Case I production levels are based on projected construction and operation of eight plants by 1985, and represent about 10 percent of the estimated potential productive capacity of the selected tracts with 54 billion barrels of reserves in the Mahogany Zone. Although sizable volumes of water are needed for shale oil production, which may limit production over the long term, sufficient water is available for the anticipated production through 1985.

Future government policies will play a very significant role in both the timing and magnitude of oil shale development. Federal leasing policies will influence the level of production because about 80 percent of the oil shale resources of the Green River Formation in Colorado, Utah and Wyoming are located on federal lands. To develop the production projections of Case I, federal policies would have to be changed to (a) make adequate reserves available, (b) permit individual company holdings of at least 10,000 to 20,000 acres of federal oil shale leases per state, and (c) remove tracts under commercial development from acreage limitations.

Costs Outlook

The oil shale report uses the DCF method for calculating rates of return for various price levels of syncrude produced from oil shale, making the required assumptions that are consistent with the projected practices in the oil shale industry. These assumptions were made for a project (mining, retorting and upgrading facilities) that is thought to be typical as to size, location, investment costs, operating costs, etc.

There is no ongoing oil shale industry; therefore, the economic analysis must necessarily be addressed to "new oil" produced from facilities constructed by "new capital."

Required syncrude "prices" in 1970 dollars were calculated for three DCF rates of return on investment and two varieties of high-quality oil shale. All "prices" reflect invested capital needed for a single production complex of two mines, two retorts and one upgrading plant. For a 15-percent DCF rate of return, 30-gal/ton oil shale produces syncrude at "prices" ranging from $5.60 to $5.80 per barrel; 35-gal/ton oil shale produces syncrude at "prices" ranging from $5.10 to $5.30 per barrel.

Calculations of the above "prices" include estimated royalty costs but *do not include leasing costs or bonus payments.* Investment and cost assumptions are sufficient to meet present-day environmental standards, but environmental costs will likely increase if regulations become more restrictive.

Various governmental policies relating to tax, royalty and land use will have significant effects on the economics of oil shale development. Assuming 35-gal/ton shale and 15-percent DCF rate of return, the effect on the "price" of syncrude resulting from assumed policy changes can be estimated as follows:

- The combined effect of (a) increasing depletion allowance from the present 15 percent on the crude shale oil values to 22 percent on the syncrude values, (b) retaining the 7 percent investment tax credit, and (c) shortening depreciation life to 5 years (as recently proposed) reduces the calculated syncrude "price" by $0.70/bbl. Applying this reduction to the initial commercial plant would give a calculated syncrude "price" in the range of \$4.40-\$4.60/bbl.

- Suspending the present Federal Government royalty on oil shale, which is graduated up to \$0.17/ton for 35-gal/ton shale, will reduce the calculated syncrude "price" by \$0.19/bbl.
- The economic effect of a prolonged delay in initiating plant start-up for ecological or other reasons would be substantial. Such a delay could result from the time required to purchase and install additional environmental control equipment to comply with sudden and more restrictive changes in the law. For example, a 12-month delay would increase the calculated syncrude "price" by \$0.55/bbl.

Outlook for New Technology

No attempt was made to quantify anticipated technological improvement, although the effects of such improvements on oil shale exploitation could be significant, as producers gain operational experience. Development of an economical *in situ* method would be an important step towards eventual recovery of deeply buried oil shale resources. Additionally, modifications of the presently available retorting processes could make possible the production of syngas from oil shale.

Findings—Other Energy Forms

This section discusses the contribution to the Nation's energy requirements that other energy resources and energy conversion devices can make. These include moving water (hydroelectric), tar sands, geothermal energy, solar energy, combined-cycle plants for electric power generation and other energy conversion devices.

Hydroelectric energy will continue to make a relatively minor contribution over the next 15 years. New energy sources are expected to make a modest contribution prior to 1985, but they will become increasingly important after 1985. The combined cycle could become a significant factor in new plants by 1985. Other new energy conversion technologies are not expected to have a significant impact on the generation of electricity by that date.

Hydroelectric Energy

Growth in hydroelectric power is projected at only 1.6 percent per year in the period to 1985, because there are few suitable dam construction sites remaining. Hydroelectric power will, therefore, decline in importance as a component of total U.S. energy production, from about 4 percent in 1970 to about 3 percent in 1985.

Pumped-storage hydroelectric plants will find increasing use by 1985 as an economical way of *storing* energy (not as a primary energy source). Nuclear power plants will serve as the primary energy source, and in off-peak hours, will pump water into storage reservoirs. Since they will be used for peak-load power generation, the pump-storage plants will compete with the gas turbine generators that are now largely used for that purpose. By 1985 the potential electric energy available from pumped-storage plants may be equivalent to 15 percent of the electric energy generated in conventional hydroelectric plants.

Tar Sands

Tar sands deposits in the United States are quite small. There are five potentially commercial, domestic tar sands deposits, all located in Utah, with oil resources estimated at 17 to 28 billion barrels. Exploitation of the domestic tar sands deposits is expected to be limited by both physical and technological factors. Lack of water for processing, potential ecological problems and the absence of developed exploitation technology make production unlikely by 1985. Accordingly, changes in government policy on land use would not materially improve the commercial attractiveness of domestic tar sands deposits.

The potential resources of the Athabasca tar sands deposits in northern Alberta are estimated to be about 400 billion barrels of bitumen—in contrast to the smaller U.S. deposits—and could yield 174 billion barrels of syncrude. In addition, large deposits of heavy oils are located in western Canada. One commercial tar sands plant is presently in operation and others are in various stages of planning. Continued development of Canadian tar sands and heavy oil deposits could make a contribution of 1.25 MMB/D to the Western Hemisphere's supply of crude oil by 1985, including some *in situ* production.

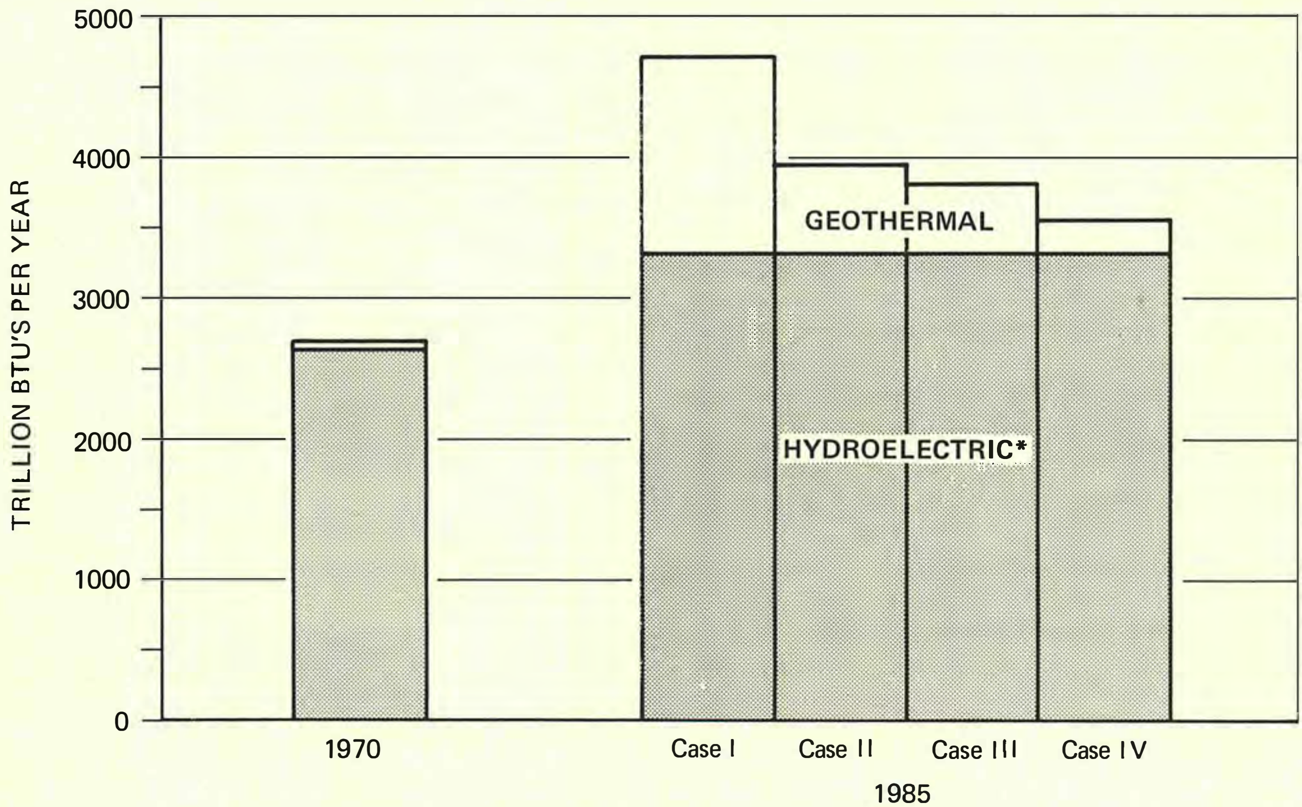
Geothermal Energy

Where hot portions of the earth's crust are in close enough proximity to underground water sources, the resulting steam can be utilized to drive conventional steam turbine generators. Even if geothermal energy sources (steam wells, hot water) are developed at the relatively optimistic rate projected for Case III, they will supply only 1 percent of U.S. electric energy requirements in 1985. Projection of energy to be derived from geothermal sources is subject to much greater uncertainty than projections of energy from conventional drilling operations for oil and gas. No experience exists with respect to finding rates as a function of total area explored or number of feet drilled. The success ratio in drilling during the next 5 years will thus have a vital bearing on future development of geothermal sources.

Case II projections of 9,000 MWe of installed capacity by 1985 assume that large areas of land will be available for prospecting. Although development of geothermal energy is seen as having little environmental impact, this does not rule out delays over ecological questions. Under the assumptions of Case I, specifically maximum technological progress with no impediments to development, installed capacity could be 19,000 MWe, or more than twice as great as Case II by 1985. This would depend upon rapid development of the technology required to extract the energy present in hot water systems (as opposed to dry steam systems). Case III assumes 7,000 MWe by 1985, and Case IV assumes 3,500 MWe by 1985. The total contribution of hydroelectric and geothermal energy are summarized on Figure 9.

Energy Conversion to Electric Power

To significantly affect the national average efficiency of electrical power generation in 1985, new innovations would have to be technologically proved at the present time. This is because existing electric generating plants have a life-span of



** For the purposes of this study, the projection of hydroelectric power generation for Cases I–IV in 1985 was assumed to be the same as that projected in the Initial Appraisal (316 billion KWH).*

Figure 9. Projected Hydroelectric and Geothermal Energy Supply.

several decades, and new plants have long construction lead times. Only one such technological innovation—the combined-cycle plant—is currently available. The combined-cycle plant utilizes waste heat from large gas turbines (driven by gases from combustion of hydrocarbon fuels) to generate steam for conventional steam turbines. The advantage of this type of plant is that it generates more electricity from the same amount of fuel than does a gas turbine power generating unit. The best combined-cycle plants that might be built in 1985 are projected to use almost 30 percent less fuel than conventional steam plants being built in 1972. Nevertheless, due to the large number of existing plants, the national heat rate (BTU requirement/KWH) is projected to decline only 8 percent from 10,666 in 1972 to 9,800 in 1985. By 1985, the combined cycle could represent about one-third of the fossil-fuel plant construction.

The following energy sources and conversion technologies are summarized briefly though they are *not* expected to have a significant impact on the generation of electricity by 1985.

- *Gasification of Coal to Low-BTU Gas* for most existing steam-electric utility plants and large industrial users of energy is not likely to be economic. When compared to the cost of stack gas scrubbing processes, or the burning of clean fossil fuels, gasification of coal for use in *new*, combined-cycle plants does look attractive. Sulfur removal would be facilitated by the high-pressure conditions present during gasification.
- *Magnetohydrodynamics* involves the generation of electricity by a moving stream of hot ionized gas rather than by a moving mechanical dynamo. This concept is unlikely to be developed prior to 1985, due to the difficulty of technological problems involved.
- *Fuel Cells* save on transmission costs by shifting the point of electricity generation from a central station to the point of consumption. Commercial testing of fuel cells should be completed by 1975. The fuel cell will be no more efficient than other means of producing electric power and is, therefore, unlikely to have a major effect on the total energy requirements.
- *Total Energy Plants* utilize hydrocarbon fuels to drive electric generators to meet electrical needs in a relatively small area (small industrial establishments, etc.) and utilize heat recovery to meet the additional energy needs of the same area. The plant has high system fuel efficiency, but its economics are favorable only in areas of low fuel costs. No significant contribution is expected prior to 1985.
- *Thermionic Devices* are another way of increasing efficiency of energy utilization in fossil-fueled steam plants. They are not expected to make a significant contribution prior to 1985, unless difficult materials problems are solved.
- *Other Energy Sources*, including solar energy and energy from agricultural products, are unlikely to make a significant contribution prior to 1985.

Findings — Water Availability

Electric power plants require large volumes of water for cooling purposes. Plants to produce synthetic oil and gas need large volumes of water, both for processing and cooling. For example, a shale oil plant requires 3.4 barrels of water and a coal liquefaction plant requires 5.3 barrels of water for each barrel of oil produced. Some of this water requirement can potentially be reduced, but this would increase the cost of the oil produced.

Many such plants to be constructed by 1985 will have to be built in relatively arid regions of the western states. Adequate surface water exists in the western state area generally to meet projected energy requirements,* but much of it is physically separated from the energy resources. Also, legal restrictions could impede its redeployment. A billion-dollar program to construct dams and aqueducts would have to be initiated almost immediately to assure sufficient water availability to meet the maximum energy supply projections set forth in supply Case I; Case IV would permit a delay of 2 years. Other needs of the area make this program necessary in the near future regardless of the development of the synthetic fuel industry.

The most critical states with regard to water availability for new energy plants are Montana and Wyoming. Water requirements for new plants in these states can be broken down as follows:

* Underground flow was not investigated because insufficient data exists.

Type of Plant	Water Requirement (Case I—1985)	% of Total
Synthetic Gas	215 thousand acre-feet per year	32
Synthetic Oil	150 thousand acre-feet per year	22
Coal-Electric	310 thousand acre-feet per year	46
Total	**675 thousand acre-feet per year**	**100**

The water requirements of these new plants could be largely met by the Montana-Wyoming Aqueduct as planned by the U.S. Bureau of Reclamation. This aqueduct would transport water from the Bighorn and Yellowstone Rivers into the coal-bearing regions of Montana and Wyoming. In order to be in service by 1981—as required by the projections in Case I—the engineering planning work would have to begin in 1972. The project, estimated to cost $750 million, will require federal funding for construction. The cost of the project could be repaid by those companies utilizing the water or mining the coal on federal lands.

Aside from the need to begin work immediately on this major construction project, the other major problem area is the need to settle disputes over water rights or water allocations. In the southwestern states of Arizona and New Mexico, in particular, the present allocation of water to the energy sector is insufficient.

Chapter Four

Foreign Oil and Gas Availability

Chapter Four
Foreign Oil and Gas Availability

This chapter investigates the availability of foreign oil and gas supplies because large volumes of imports will probably be necessary to meet U.S. petroleum requirements in the period to 1985. Total supplies—domestic, synthetic and imported—are tabulated to show the sources of the oil and gas projected to meet U.S. requirements for these fuels.

Foreign Oil

Based on the projected 1971-1985 growth rates for non-Communist foreign energy demand of 6.3 to 6.6 percent per year and oil consumption growth rates of 6.4 to 7.4 percent per year, this area will consume 257 to 277 billion barrels during the period. The United States will consume about 94 to 115 billion barrels in this time; thus, total oil consumption in the non-Communist world will be in the range of 350 to 400 billion barrels between 1971 and 1985.

As of January 1, 1972, it was estimated that non-Communist world proved crude oil reserves totaled 463.4 billion barrels. Moreover, assuming favorable political and economic conditions, international oil suppliers should be capable of finding and developing 450 to 550 billion barrels of additional reserves outside the United States in the next 15 years, although at increased costs. Thus, existing reserves coupled with the non-Communist resource base remaining to be discovered, as it is presently appraised, are sufficient to meet requirements up to 1985. Finding these new reserves, however, is primarily dependent on the industry's ability to attract large amounts of capital while confronted with a variety of uncertainties on such items as increased taxation, foreign government policies, participation demands, capital recovery restraints and currency exchange adjustments.

Potential developable non-Communist liquid hydrocarbon capacity through 1985, shown in Table 17, indicates that supply potential, if fully developed, should exceed anticipated demand throughout the period. However, supplies will tighten between 1971 and 1985 as ready availability of low-cost oil declines, with the non-Communist reserve/production ratio dropping from 27 in 1972 to between 14 and 19 in 1985. New increments of crude oil producing capacity will be increasingly more costly as more oil comes from the high-cost offshore and Arctic regions; these increasing costs will necessarily be reflected in increased prices. Towards the end of the century, foreign oil supplies may prove insufficient to meet all potential demands.

TABLE 17
POTENTIAL DEVELOPABLE UNITED STATES & NON-COMMUNIST FOREIGN LIQUID HYDROCARBON CAPACITY

(Including Synthetics from Coal & Shale in United States and from Tar Sands in Canada*)

	MMB/D			
	Actual 1970	1975	1980	1985
U.S. Case III	11.3	9.8	11.7	12.3
Canada	1.6	2.3	3.7	4.7
Latin America	5.3	5.8	7.0	7.8
Subtotal Western Hemisphere	**18.2**	**17.9**	**22.4**	**24.8**
Western Europe	0	1.5	3.0	4.0
North Africa	4.5	5.2	6.0	7.0
West Africa	2.5	3.8	5.0	6.5
Subtotal Africa	**7.0**	**9.0**	**11.0**	**13.5**
Middle East	17.0	30.0	40.5	50.5
Far East/Oceania	2.0	3.0	4.0	5.5
Subtotal Eastern Hemisphere	**26.0**	**43.5**	**58.5**	**73.5**
Total Non-Communist World Supply	**44.2**	**61.4**	**80.9**	**98.3**
Total Non-Communist World Demand	**40.0**	**55.56**	**72.75**	**87.93**

* More detailed discussions of these synthetic sources are contained in the supply sections.

TABLE 18

TOTAL AVAILABLE OIL
(MMB/D)

	Actual	PROJECTED											
		Case I			Case II			Case III			Case IV		
	1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Conventional Petroleum Liquids	11.3	10.2	13.6	15.5	10.2	12.9	13.9	9.8	11.6	11.8	9.6	8.9	10.4
Synthetic Liquids													
From Coal	–	–	.1	.7	–	–	.1	–	–	–	–	–	–
From Oil Shale	–	–	.2	.8	–	.1	.4	–	.1	.4	–	–	.1
Oil Imports	3.4	7.2	5.8	3.6	7.4	7.5	8.7	8.5	10.6	13.5	9.7	16.4	19.2
Total Supply*	**14.7**	**17.5**	**19.6**	**20.5**	**17.6**	**20.5**	**23.1**	**18.3**	**22.3**	**25.8**	**19.3**	**25.3**	**29.7**

* Totals may not agree due to rounding.

TABLE 19

TOTAL AVAILABLE GAS
(TCF/YEAR)

	Actual	PROJECTED											
		Case I			Case II			Case III			Case IV		
	1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Lower 48													
Onshore	22.2	18.7	17.3	17.1	18.5	16.5	15.2	17.6	14.3	12.0	17.4	13.1	9.6
Offshore		4.9	6.9	9.1	4.8	6.3	7.8	4.3	4.8	5.5	4.1	4.0	3.6
Alaska, North Slope	–	–	1.4	3.3	–	1.3	2.7	–	1.1	2.2	–	–	1.3
Alaska, South	.1	.2	.2	1.1	.2	.2	.9	.2	.2	.6	.2	.2	.4
Total Conventional* (Wellhead Production)	**22.3**	**23.7**	**25.9**	**30.6**	**23.6**	**24.3**	**26.5**	**22.0**	**20.4**	**20.4**	**21.8**	**17.3**	**15.0**
Synthetic Gas													
From Coal	–	–	.6	2.5	–	.4	1.3	–	.4	1.3	–	.2	.5
From Liquids	–	.6	1.3	1.3	.6	1.3	1.3	.6	1.3	1.3	.6	1.3	1.3
Gas from Nuclear Stimulation	–	–	.2	1.3	–	.1	.8	–	.1	.8	–	–	–
Imports													
LNG	†	.2	2.3	3.2	.2	2.3	3.4	.2	2.3	3.7	.2	2.3	3.9
Pipeline	.8	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7
Total Supply*	**23.1**	**25.5**	**31.9**	**41.6**	**25.4**	**30.0**	**36.0**	**23.8**	**26.1**	**30.2**	**23.6**	**22.7**	**23.4**

* Totals may not agree due to rounding.
† Less than 10 BCF.

A projected Western Hemisphere petroleum liquid supply/demand balance indicates that the U.S. oil consumer will become increasingly dependent on the Eastern Hemisphere, which will probably have to supply about three-fourths of U.S. oil imports in 1985, despite the development of domestic oil shale and other synthetic fuels. Production (both conventional and synthetic) available for net exportation (exports minus imports) by Canada is expected to grow to 1.7-2.0 MMB/D by 1985 from a 1970 net position of about zero. Meanwhile, exportable production from Latin America will likely decline from the 1970 level of 2.5 MMB/D to 0.8-1.3 MMB/D by 1985 as local requirements grow.

Foreign Gas

It is estimated that there are 895 TCF of proved reserves and about 6,200 TCF of potential gas reserves remaining to be discovered in the non-Communist areas of the world. In 1971 non-Communist gas production, excluding the United States, was only 16.3 TCF so there appears to be an adequate supply of natural gas reserves available for long-range import projects to supplement domestic natural gas supplies. However, physical availability of foreign natural gas resources must be accompanied by satisfactory regulatory and economic conditions if import projects are to be planned and initiated with confidence. In this regard, the market, rather than a regulatory agency, should determine the appropriate price level for natural gas imports.

LNG imports involve such logistical considerations as construction of specialized tankers and development of required port facilities. Under a most favorable set of assumptions, annual LNG imports could reach the equivalent of 4 TCF and LPG imports could reach 0.62 TCF by 1985. Proved reserves are sufficient to support these import projections without having to depend upon future discoveries. However, additional development drilling may be required to meet daily production requirements.

Based on the indicated large potential of the Canadian frontier areas, it is anticipated that increased volumes of Canadian gas will become available as exploration and development programs intensify and transmission systems are constructed. However, it appears that such pipeline imports are not likely to achieve annual delivery of more than 2.7 TCF by 1985.

Total Oil and Gas Availability

Oil

Total petroleum-liquid supplies include synthetic liquids derived from coal and oil shale as well as conventionally produced domestic crude oil, natural gas liquids and oil imports. The total liquid volumes available to satisfy U.S. demand in 1975, 1980 and 1985 are shown for Cases I-IV in Table 18.

Gas

Total natural gas supply includes conventional domestic supply, SNG from coal, SNG from liquids, imported LNG, pipeline imports and gas from nuclear-stimulated wells. Quantities of gas available in 1975, 1980 and 1985 are shown for Cases I-IV in Table 19.

Chapter Five

Financial Effects

Chapter Five
Financial Effects

Capital Requirements

Total capital requirements for the period 1971-1985 for resource development, processing and primary distribution are projected to range from $215 billion to $311 billion in the four principal cases studied.

Under the Electricity Task Group's base case (Condition 1), an additional $235 billion would be required for power plant construction and transmission facilities. Over the same period, $0.7 billion to $1.1 billion would be needed for water requirements, bringing the total capital requirements to a range of $451 billion to $547 billion.

Not included in these estimates are other major sums required for petroleum marketing, gas and electricity distribution, and the development of overseas natural resources to satisfy U.S. import requirements.

Capital requirements by individual resource sectors are summarized on Table 20 and commented upon as follows.

Oil and Gas

Projected U.S. capital expenditures over the 1971-1985 period for the exploration, development and production of domestic oil and gas range from $88 billion (Case IV) to $171.8 billion (Case I)—or an annual average investment over the period of $5.8 billion to $11.5 billion. These figures compare with $4.8 billion for 1970.

Capital investment for oil pipelines, including the Alaska pipeline and expansion of existing domestic pipeline systems, is estimated at $7.5 billion. Total gas transportation capital requirements, including pipelines, underground storage, ships, liquefaction plants, trucks, rail cars and processing plants are projected to range from $29.5 billion to $56.6 billion.

The capital requirements for refineries, tankers, terminals and gas transmission systems all vary from Case I to Case IV. The reason for the variation in gas transmission requirements is obvious—with greater domestic gas development, in Case I, more transmission investment is needed. More tankers and terminals are needed for Case IV because of the increase of oil imports. The reason for the difference in refining investment is not as obvious—the greater domestic gas supply in Case I reduces total oil demand as compared to Case IV, and because total oil demand is smaller in Case I than it is in Case IV, less refining investment is needed.

Capital requirements for marine transportation of oil imports assume the use of vessels averaging 250,000 DWT each. Under Case III conditions, over 400 of these vessels would be required, at a cost of $36 million each (foreign construction), for a total capital cost of approximately $14 billion. Capital requirements for the other three cases are derived from this estimate in proportion to the volume of total waterborne oil imports.

Additional terminal and transportation costs are estimated to require capital investment on the order of $2 billion, bringing the total investment for ocean transportation and terminals into the range of $2 billion to $23 billion. In total, cumulative oil and gas capital expenditures between 1971 and 1985 range from $186.0 billion to $256.9 billion.

Synthetics

Syngas plants for gasification of petroleum liquids are estimated to require an investment of about $5.0 billion; similar plants for coal gasification and liquefaction will require $1.7 billion to $12.0 billion.

Capital requirements to support the mining and processing of oil shale to marketable syncrude are calculated to range from $0.5 billion (Case IV) to $4.0 billion (Case I). Total investment for domestic manufacture of synthetic oil and gas may range from $7.2 billion to $21.0 billion.

TABLE 20

SUMMARY OF CUMULATIVE CAPITAL REQUIREMENTS
U.S. ENERGY INDUSTRIES 1971-1985
(Billions of 1970 Dollars)

	Initial Appraisal	Supply Cases I	II	III	IV
Oil and Gas					
Exploration & Production	92.4	171.8	144.8	135.1	88.0
Oil Pipelines	3.5	7.5	7.5	7.5	7.5
Gas Transportation	21.0	56.6	46.9	39.8	29.5
Refining*	20.0	19.0	24.0	30.0	38.0
Tankers, Terminals	14.5	2.0	9.0	16.0	23.0
Subtotal	**151.4**	**256.9**	**232.2**	**228.4**	**186.0**
Synthetics					
From Petroleum Liquids	–	5.0	5.0	5.0	5.0
From Coal (Plants Only)	1.5	12.0	4.6	4.6	1.7
From Shale (Mines & Plants)	0.5	4.0	2.2	2.2	0.5
Subtotal	**2.0**	**21.0**	**11.8**	**11.8**	**7.2**
Coal†					
Production	9.3	14.3	10.4	10.4	9.4
Transportation	6.0	6.0	6.0	6.0	6.0
Subtotal	**15.3**	**20.3**	**16.4**	**16.4**	**15.4**
Nuclear					
Production, Processing, Enriching	5.0	13.1	11.0	8.5	6.7
Total All Fuels	**173.7**	**311.3**	**271.4**	**265.1**	**215.3**
Electric Generation, Transmission‡	200.0	235.0	235.0	235.0	235.0
Water Requirements	N.A.	1.1	0.8	0.8	0.7
Total Energy Industries	**373.7**	**547.4**	**507.2**	**500.9**	**451.0**

* Based on maximum U.S. requirements, some of which may be spent outside the United States

† Cases I-IV include capital requirements for coal for synthetic fuels. The Initial Appraisal includes only capital requirements for coal for conventional markets.

‡ Condition 1; capital requirements under all six conditions postulated by the Electricity Task Group are as follows.

Condition	Cumulative Investment (1971-1985) Billion 1970 Dollars 1	2	3	4	5	6
Power Plant Construction	181	183	186	169	196	163
Transmission (estimated at 30% of Condition 1 Cumulative Power Plant Investment)	54	54	54	54	54	54
Total	235	237	240	223	250	217

Coal

Coal production expenditures are projected to range from $9.4 billion to $14.3 billion; to this must be added transportation expenditures approximating $6.0 billion, for a range of required total coal capital investment of $15.4 billion to $20.3 billion.

Nuclear

Production of uranium and processing through the nuclear fuel cycle (including enrichment) are projected to require capital expenditures in the range of $6.7 billion to $13.1 billion in the four cases analyzed. The capital required for the construction of nuclear electric generating plants is included in the electricity total capital requirement.

U. S. Balance of Trade in Energy

Trade in energy fuels, transactions traceable to the international operations of U.S.-based energy companies and trade in activities closely related to energy are major factors in the Nation's overall balance of *payments*. Some aspects of this complex of activities can be quantified; many cannot.

This section estimates the balance of *trade* in energy fuels for 1970, 1975 and 1985 that is directly relevant to this report. Also the policy implications of these possible balances are examined. Capital and income flows involved in the international operation of U.S. energy companies and activities allied to energy, however, would require a major separate study.

In 1970, petroleum imports cost the Nation $3.4 billion; natural gas imports cost $0.2 billion. Thus the total energy fuel imports bill was $3.6 billion. Petroleum, steam and metallurgical coal export earnings provided a partial offset of $1.5 billion. Therefore, the total deficit arising from trade in energy fuels was $2.1 billion.

Considering the same factors in 1975, the estimated deficit of the balance of trade in energy fuels would range from $9.5 billion to $13.2 billion in the four major supply cases described in Chapter Two. Under the conditions described in the Initial Appraisal, the 1975 deficit would be $9.6 billion. These estimates are derived as follows.

BALANCE OF TRADE DEFICIT IN ENERGY FUELS, 1975

	$ Billion				
	Initial Appraisal	Case I	Case II	Case III	Case IV
Oil imports[1] (delivered)	11.0	10.9	11.1	12.9	14.6
Natural gas & LNG imports	0.5	0.5	0.5	0.5	0.5
Total energy fuels imports	**11.5**	**11.4**	**11.6**	**13.4**	**15.1**
Oil exports	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Steam coal exports	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Metallurgical coal exports	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Total energy fuels exports	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**	**(1.9)**
Total energy fuel deficit	**9.6**	**9.5**	**9.7**	**11.5**	**13.2**

(1) Including synthetic gas feedstocks.

The 1975 energy fuel deficits are 4.5 to 6.3 times greater than the corresponding estimated 1970 deficit of $2.1 billion, and 2 to nearly 3 times the 1970 overall U.S. balance of payments deficit of

$4.7 billion. These substantial deficits are close at hand.

After 1975 the deficits can be expected to grow even larger, except under the favorable assumptions of Case I. The 1985 projections are shown in the table below.* By 1985, the deficit for Case II is projected to increase further by over $5 billion from 1975. In comparison with 1975, Cases III and IV in 1985 are estimated to be higher by $11 billion and $18 billion, respectively. The assumptions and judgments underlying the 1975 and 1985 estimates are set forth in the full report.

ment of domestic energy resources and maintenance of import controls.

The projected sizable increase in the deficit resulting from trade in energy fuels would create significant problems for the U.S. economy which cannot prudently be ignored. Unless export earnings are very strong in areas other than energy, the substantial demand for foreign exchange arising from the energy deficit may create problems for the dollar. Furthermore, quite aside from any balance of payments difficulties, large-scale energy imports pose significant issues of national security.

BALANCE OF TRADE DEFICIT IN ENERGY FUELS, 1985

	$ Billion				
	Initial Appraisal	Case I	Case II	Case III	Case IV
Oil imports[1] (delivered)	22.4	5.4	13.1	20.4	29.1
Natural gas & LNG imports	5.5	4.9	5.0	5.3	5.4
Total energy fuels imports	**27.9**	**10.3**	**18.1**	**25.7**	**34.5**
Oil exports	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Steam coal exports	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Metallurgical coal exports	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)
Total energy fuels exports	**(2.8)**	**(2.8)**	**(2.8)**	**(2.8)**	**(2.8)**
Total energy fuel deficit	**25.1**	**7.5**	**15.3**	**22.9**	**31.7**

(1) Including synthetic gas feedstocks.

Indirect or direct action can be taken either to offset the impact of the energy fuel deficit and/or to actually reduce the deficit. Indirect action might include efforts to reduce obstacles to exporting U.S. goods, plans for restricting imports of goods other than energy fuels, or altering relative exchange rates. Direct action would encompass policies to provide greater access to federal lands, tax incentives or higher prices to promote development of domestic energy resources and maintenance of import controls. From a national security viewpoint, it would be better to reduce the projected deficit in domestic energy supplies rather than to offset a large deficit in balance of trade through other measures.

* For purposes of these calculations, f.o.b. oil prices by 1985 were assumed to be no higher than 1975 prices under currently existing contract provisions with producing nations as explained in the full report.

Chapter Six

Energy Trends Beyond 1985

Chapter Six
Energy Trends Beyond 1985

Introduction

Suggesting developments in the U.S. energy situation in the period from 1985 to 2000 involves considerable conjecture. Energy production, distribution and consumption—inextricably interwoven through economic and social activities—change as the latter change. Also, government regulations and policies profoundly influence the operations of the energy industries. Consequently, a multitude of developments may occur over the next 30 years that would affect the Nation's demand for energy as well as the technology to develop and utilize energy. Since so many factors impinge on the Nation's energy outlook, only broad trends can be identified. These trends reveal the future energy options available to the Nation and the related actions needed to implement these options. Projection of these general trends should be frequently monitored in the future against actual developments to assure that they have continuing validity.

It was considered inappropriate to develop supply/demand balances for the year 2000. The four supply cases developed for the 1971-1985 period indicate a wide range of future possibilities. With such diverse starting points for 1985, it is evident that a much wider range of demand and supply projections are possible by the end of the century. Indeed, depending on developments, the Nation's supply/demand balance in 2000 could range all the way from total national self-sufficiency in energy supplies to an alarming degree of dependency on imports.

Assuming the continuation of the projected growth in energy requirements, the present assessment of the energy resource base, and only moderate advances over the existing technology for developing and delivering energy supplies, there will likely be a trend toward sharply rising costs and physical limitations of energy resources. This is particularly true of oil and gas, both domestic and foreign.

At present, the identifiable approaches for countering this trend toward higher energy costs and physical limitations on domestic sources of supply may be grouped within seven principal categories: (1) location of more reserves of the energy fuels now used, (2) development of greater ability to make synthetic fuels, (3) increased efficiency of producing fuels, (4) reduced energy demand through increased efficiency in the utilization of fuels, (5) a shift from the less abundant to the more abundant sources of energy supply, (6) increased imports of fuels, and (7) a turn to totally new technologies for the supply of energy. Each of these seven approaches will be discussed more fully in a later section. The demands on energy supplies in the last part of this century are likely to be so great that all of them will probably have to be employed in varying degrees, if the energy needs of American society are to be satisfied.

Requirements for Energy

In projecting energy requirements to the year 2000, special consideration needs to be given to population trends, economic activity, efforts to improve environmental quality, and cost and efficiency in utilizing fuels. Depending on future developments in these basic factors, total energy demand at the end of the century might range between 170 and 215 quadrillion BTU's, as shown in the following tabulation:

Projections of U.S. Total Energy Demand

	Volume (Quadrillion BTU/Yr)		Growth Rate (Percent)	
Case	1985	2000	1981–1985	1985–2000
High	130.0	215	4.4	3.4
Intermediate	124.9	200	4.2	3.2
Low	112.5	170	3.4	2.8

While factors such as a continued high level of emphasis on environmental quality tend to increase energy consumption, the growth rate in U.S. energy demand is expected to slacken in the last 15 years of the century because of the effect of the following trends:

- A lower rate of population growth
- A more service-oriented economy
- Changes in social values and life-styles, including smaller families, increased multiple dwellings, smaller cars and greater use of mass transit
- Higher energy costs.

The dominant factor in energy growth during the 1985-2000 period will be energy requirements for electricity. By the year 2000, such requirements will account for nearly half the primary fuels consumed. During this period the growth rate for electricity is expected to average more than 5 percent per year, while non-electric energy consumption will grow at less than 2 percent per year. This high rate of growth for electricity will be stimulated by economic factors (the costs of electricity generated in nuclear power stations are expected to increase at a slower rate than fossil fuel costs) and changing life-styles (more multiple-family dwellings and greater population concentration in the moderate climate areas will bolster electrical heating and air conditioning).

Recapitulation of 1985 Fuels Technology and Resource Positions

Three essentials are necessary if the Nation's energy resource potential is to be fully realized:

- A workable societal consensus regarding the proper balance between environmental safeguards and energy development and utilization
- Sound government policies to provide access to and incentives for resource development
- Capable, far-sighted energy industries to develop the required resources while satisfying the Nation's need for clean energy.

If these three fundamental prerequisites exist, the primary determinants of how successfully the Nation can meet its energy requirements in the 1985-2000 period will be (a) the technology available in 1985 and later years for producing the major fuels, and (b) the size of the resource base for these fuels. Alternative new energy sources, such as fusion power or solar energy, are not likely to be in widespread use by the year 2000, because a lead time of decades probably will be required to bring the requisite technologies to full commercial availability.

The sections that follow discuss the fuel technology and fuel resources likely to be available in 1985.

Fuels Technology

Based on the analyses of 1985 conditions earlier in this report, the "state-of-the-art" in fuels technology at the outset of the 1985-2000 period is likely to be as follows:

- **Oil:** Anticipated recovery efficiency of oil-in-place will have increased from an average of 31 percent in 1970 to 37 percent in 1985. By 1985 anticipated ultimate recovery efficiency in new reservoirs discovered will be about 50 percent, due to technological improvements. Drilling will be carried out in increasingly deeper formations. Hopefully, drilling capability will have advanced to the point where it can cope with the formidable conditions found in such areas as the offshore Arctic. This latter ability will be of particular importance, because vast resources are believed to exist in that region.
- **Gas:** Improved drilling capability will make it possible to develop very deep gas formations. Nuclear explosives should be proved as a means of fracturing low-productivity gas reservoirs. Systems for liquefying and transporting LNG should be well developed.
- **Coal:** The environmental problems associated with use of high-sulfur coal will have been solved. Underground mining methods will have made considerable improvements.
- **Nuclear:** The breeder reactor, approaching the commercial application stage, will extend the useful life of domestic uranium resources. The breeder and the high-temperature gas reactor will have greater thermal efficiency than the light-water reactor.
- **Synthetic Fuels:** Shale oil, Canadian tar sands and coal gasification industries all will be advanced beyond the pioneering stage. Production of liquids from coal is expected to be in the pioneering stage.

- **New Engery Forms and New Conversion Devices:** Combined-cycle power plants will be commercially available. Fusion reactors, solar energy, magnetohydrodynamic (MHD) units, hydrogen and other new energy forms are likely to still be in the research and development or working prototype stage. Of course, technological advances unforeseen at this time could occur to hasten their development.

Domestic Resource Position

A rough projection of the resource base available at the outset of the 1985-2000 period has been developed from present estimates of potential domestic resources, adjusted to reflect reserve additions and production withdrawals in the 1971-1985 period. (The data below reflect the range of supply Cases I-IV in the 1971-1985 period which have been described in Chapter II.) The estimates of the resource position for various fuels thereby reflect current thinking; however, advances in technology (greater than those identified above) and increased knowledge could further add to the resource base for particular fuels.

- **Oil:** In 1985, between 58 and 67 percent of the present estimate of discoverable oil-in-place will have been found; the amounts remaining to be recovered will range from 265 to 340 billion barrels of oil-in-place. If Case II assumptions were to prevail in the 1971-1985 period, the additional amount of oil available for discovery, assuming a 50-percent discovery rate, would correspond to 32 years' supply at the 1985 rate of production. Under Case III, the corresponding figure would be 40 years' supply.
- **Gas:** By 1985, between 44 and 58 percent of the present estimate of ultimately discoverable natural gas will have been found; the amounts remaining to be discovered will range from 770 to 1,040 TCF. Under Case II assumptions, the additional resource available for discovery would correspond to 32 years of supply at 1985 production rates; under Case III, the corresponding figure would be 46 years.
- **Coal:** Remaining coal reserves recoverable in 1985 under present mining methods will range from 133 to 136 billion tons, depending on whether Case I-IV conditions prevail over the 1971-1985 period. These reserves would suffice for over 100 years at the Case II, 1985 level of demand; they also represent only about 4 percent of the 3.2 trillion tons of estimated total potential coal resources in place.
- **Oil Shale:** Well defined and readily accessible resources of oil shale in place will be at least 125 billion barrels. Assuming a 60-percent recovery rate, this resource base would be equivalent to about 20 years' supply of conventional crude at the 1985 Case II conventional crude oil production rate. In addition to these defined resources, potential and speculative resources total an additional 1,550 billion barrels.
- **Uranium:** Previous uranium exploration activity has been concentrated in the present producing areas, which make up less than 10 percent of the total region where signs of uranium occur; even these areas are not completely explored. It is, therefore, impossible to estimate accurately ultimate domestic uranium reserves. Because of the large unexplored regions with potential for uranium ores, the uranium resource base is presumed adequate to meet rapidly rising requirements until the breeder reactor becomes the major reactor type ordered in the 1990's and beyond.

In speculating about the Nation's energy resources at a future point in time—1985, 2000 or even later—there is a tendency to regard the Nation's resource position as a static amount of available resources. This concept assumes that there is a fixed stock of energy resources; when the stock is used up, our resources are gone. More realistically, more usefully, the Nation's energy resources should be regarded in a dynamic sense. The character of energy resources available for use in industrialized societies is changing as are judgments regarding the size of the resource base for various fuels. Two fundamental facts support this point of view:

- The ultimate size of the energy resources available in the outer crust of the earth cannot be accurately estimated. Past estimates of total resources in place have generally been low. As knowledge and engineering ability improve, estimates of energy resources may increase as a result of discoveries of very large additional deposits of oil, gas, coal, geothermal energy and uranium.

- Technological advances alter traditional measures of resources available. For example, the development of nuclear power increased total energy resources by enabling a new fuel—uranium—to become a utilizable energy source. Similarly, in future years large quantities of liquid fuel will be available from a source other than underground oil reserves, namely, from shale oil or coal liquefaction. Similarly, the advent of the fast breeder reactor will increase effective world reserves of fissionable uranium.

For thousands of years, man burned wood for energy. A few hundred years ago, the more developed countries switched to coal, and then in turn to the other fossil fuels—oil and gas. At present the industrialized countries are in the early stages of large-scale use of nuclear energy. The full range of ways that society's increasing energy needs will be met in the future is uncertain. However, historical precedent provides assurance of man's increasing technological capability to create and use new energy forms. Nuclear energy represents the first major supplement to the conventional fossil fuels. The next major contributor might be either (a) fusion, which would utilize the virtually limitless quantities of hydrogen isotopes in seawater; (b) solar energy, which originally provided the energy stored in fossil fuels hundreds of millions of years ago; or (c) the geothermal energy stored within the earth's crust.

In planning for the Nation's energy supply and utilization through the end of the century, attention should concentrate on the resource base for the fuels presently utilized. But the broader perspective of technological possibilities toward the end of the century should also be considered.

Domestic Fuel Availability

Because conditions at the end of the century are subject to a great deal of uncertainty, the role of conventional domestic fuels in the year 2000 can be only approximated. The following table summarizes a range of estimates for conventional fuel supplies in the year 2000. The four supply cases for the 1971-1985 period give a wide range of possible starting points in 1985 for projecting fuel supplies during the subsequent 15-year period. With such diverse starting points, the range of supply and demand projections possible by the end of the century could extend from total national self-sufficiency in energy supplies to an alarming degree of dependence on imports. The projections for the year 2000 which appear on Table 21 are based on the assumption of an intermediate level of domestic supplies in 1985. Under different assumptions for the 1985 supply position, it would be possible to develop additional projections of potential energy fuel supplies for the year 2000.

According to these projections for the 1985-2000 period, oil production generally remains at about the same level, natural gas trends downward, coal grows substantially, hydro remains relatively insignificant, and nuclear grows dramatically. The estimated volumes of oil and gas available in the year 2000 have been derived assuming an intermediate level of supply as a starting point in 1985 and a constant level of drilling in the last 15 years of the century. Increased knowledge of unexplored areas might lead to an upward reappraisal of the hydrocarbon resource base and a corresponding increase in drilling activity and resulting production.

For all of the energy sources but hydro, the projected ranges of production for 2000 are quite broad. When the extremes of these ranges are totaled, the result is a total BTU range for conventional fuels which extends from 131 to 211 quadrillion BTU's.

Energy Supply/Demand Balances and Implications

As indicated earlier, supply/demand balances have not been developed for the year 2000. Depending on developments in supply and demand, a wide range of very different conditions could be postulated. There is little foundation to judge which possible supply/demand balance is likely to exist in the year 2000 within this wide range.

Despite the considerable uncertainties regarding future demand and supply developments, it is possible to make certain inferences about conditions that will exist in the year 2000 and the proper orientation of policies in the meantime. Among the conventional domestic fuels, increases in fuel availability are more likely to come from coal and nuclear, which can be used primarily for electricity generation, while the more interchangeable fuels—oil and gas—will be less readily available, based on

TABLE 21

DOMESTIC ENERGY OUTPUT POTENTIAL IN THE YEAR 2000
BASED ON AN INTERMEDIATE LEVEL OF SUPPLY IN 1985
(Conventional Energy Sources)

	Units	1985	2000
Oil, total domestic liquid production	MMB/D	14	10 - 18
Natural gas production	TCF/yr	27	15 - 25
Coal, traditional uses only	Million tons/yr	863	1,200 - 1,700
Hydro	Billion KWH	316	340 - 380
Nuclear	Billion KWH	2,463	7,500 - 9,500
Oil, total domestic liquid production	Quadrillion BTU's/Yr	29	21 - 37
Natural gas production	Quadrillion BTU's/Yr	28	15 - 26
Coal, traditional uses only	Quadrillion BTU's/Yr	21	30 - 42
Hydro	Quadrillion BTU's/Yr	3	4
Nuclear	Quadrillion BTU's/Yr	25	61 - 102
TOTAL		**106**	**131 - 211**

the current estimated resource position. Chapter Two has indicated the limitations involved in interfuel substitution.

Seven approaches to providing sufficient energy supplies to meet U.S. requirements in the 1985-2000 period are discussed in the next sections.

Better Definition of the Resource Base and Location of More Reserves of Traditional Fuels

This is an area of special need for oil and gas, the fuels in shortest supply. But the need for finding new reserves will increasingly apply to other fuels as well. Environmental considerations in the development of energy supplies will be of great importance in the remainder of the century. This will create continuous upward pressure on the cost of producing and processing energy fuels. Proper economic incentives and access to promising areas will be necessary to enable companies in the energy industries to undertake the necessary exploratory activity to locate and develop additional reserves.

Discovery and development of deep offshore petroleum reserves could substantially increase domestic oil and gas production during the 1985-2000 period. Large areas of the continental shelf (those areas with water depths generally less than 660 feet) and virtually all of the continental slope (with water depth between 660 and 8,000 feet) are unexplored. While estimates of potential resources in these areas are highly speculative, a large proportion of undiscovered domestic oil and gas resources is believed to be located in these offshore areas.

Discovery and development of deep offshore reserves could yield significant results, but only if the following four conditions prevail: (a) international agreement is reached on the right to develop undersea resources, (b) there is a clear definition of the jurisdiction between state and federal governments to permit companies to develop these resources, (c) technology advances sufficiently to permit these resources to be found and recovered in a manner compatible with environmental goals, and (d) economic incentives are adequate to compensate for the increased costs and risks associated with operations in these areas. Unless the legal necessities and economic issues are satisfactorily resolved, corporations will not have the incentive to devise the advanced technology required to develop these vast resources in a timely manner.

Develop Production of Synthetics and Canadian Tar Sands

Synthetics represent another major source of energy to fill any existing energy gap. Because the availability of domestic conventional fuels is subject to considerable variation and because the respective technologies of several synthetics have not been fully developed, the overall contribution of these sources and their relative roles by the end of the century are by no means clear at this time. However, provisional judgments suggest that:

Shale Oil: Supplies by the year 2000 could reach about 2 MMB/D or approximately 4 quadrillion BTU's. This implies that 16 billion barrels of an estimated 54 billion barrels of reserves in the preferred minable section of the Mahogany Zone in the Piceance and Uinta Basin would have been committed by the 21st century. Thus, 38 billion barrels of preferred reserves, plus other reserves in deeper and less explored areas, would be available for future development. However, production greater than the foregoing estimate could be limited by difficulties associated with spent shale disposal, other environmental considerations and water availability. Greater development could require either the use of water now allocated to agriculture or large-scale trans-basin diversions. On the other hand, more rapid progress with *in situ* production methods could result in higher shale oil output than the foregoing estimate.

Coal-Based Gas and Liquids: Production will grow rapidly in the last part of the century. The contribution of synthetic gas and liquids from surface reserves of western coal could be about 8-10 quadrillion BTU's/year by the end of the century. Since technological problems must be solved for coal liquefaction, the largest part of this total will be syngas. Available resources of western coal will be sufficient to meet this projection.

Canadian Tar Sands: Resources are abundant. Sizable volumes of tar sands production will be required by the Canadian economy. Under favorable circumstances, these hydrocarbon resources in Canada could contribute slightly over 5 MMB/D or about 10 quadrillion BTU's to U.S. energy supplies. (This assumes that 25 percent of projected Canadian tar sands production is utilized in that country and 75 percent is exported to the United States.)

Adding together the potential contributions of oil shale, coal-based synthetics and Canadian tar sands, these energy sources could supply approximately 20-25 quadrillion BTU's. Achievement of an even higher level of supplies from synthetics and tar sands for the year 2000 should be possible, given the proper economic environment. As indicated elsewhere in this report, the basic resources are clearly present, although the degree of development possible over and above this projection is speculative. Generation of these additional supplies will depend, in varying degree, on (a) the resolution of the environmental problems; (b) the availability of sufficient water supplies; and (c) the extent of the commitment to further research and development.

Increase the Efficiency of Fuel Production, Conversion and Distribution

Increased efficiency in energy production, conversion and distribution holds perhaps the greatest potential for expanding the effective availability of energy fuels. (Efficiency in the utilization of fuels is analyzed in the next section.) Efficiency improvements can be made in several ways:

- Much can be done to increase the effective recovery of identified reserves—e.g., by employing new stimulation techniques in the production of oil and gas, developing new mining techniques to increase recovery of coal, pursuing *in situ* development of oil shales, tar sands and coal. At present rates of research spending, progress in *in situ* resource development is likely to be limited by the year 2000.
- Efficiency can be improved in the conversion of conventional energy fuels to electricity. The potential is great here. In 1970, electric power plants converted only about 33 percent of the energy in the fuels they burned into electricity. Efficiency may be improved in several ways. Combined-cycle power generators ultimately will be able to reach an efficiency of over 50 percent. The breeder reactor will greatly increase the efficiency of nuclear power plants.
- Magnetohydrodynamic generators are potentially capable of serving as high-temperature "topping" devices to be operated in series with steam turbines and generators in producing electricity. But there are a number of difficult

engineering problems to be solved before MHD can approach commercial feasibility. Construction of the first large commercial unit is unlikely before 1985. An expenditure of $100 million to $300 million in R&D funds will be required before commercial application of MHD can be achieved.

- Transmission losses accounted for about 10 percent of the total amount of electricity generated. Development of high-voltage transmission lines and the use of cryogenic techniques can reduce power transmission losses. Reducing transmission losses will be of increasing importance as energy sources are developed in areas remote from major load centers. Better means for storing electricity to meet the surge of peak load requirements are needed. Such areas of potential improvement in energy conversion and distribution should be pursued to better utilize coal and nuclear resources and to make solar power practicable.
- The projected increased use of electrical energy will result in the production of tremendous volumes of waste heat, which are not used in the generation of power. This thermal energy is presently a waste product, the disposition of which poses a potential threat to the environment in the form of thermal pollution. A more positive approach would be to recognize the heat losses as a potential energy resource and to begin to devise means of converting these losses to constructive use.

Reduce Growth of Energy Demand Through Greater Efficiency in Energy Utilization

The gap between projected domestic supply and demand could be reduced by lowering demand growth. Earlier it was indicated that total demand might be as low as 170 quadrillion BTU's in 2000; this represents a level of demand that is 15 percent less than the intermediate demand level. Reduction of energy demand growth could be accomplished either by (a) improving efficiency in energy consumption, or (b) arbitrarily restricting energy demand growth. The latter alternative would not be desirable because it would seriously retard economic growth, increase unemployment and adversely affect consumers' freedom of choice.

Greater efficiency in energy utilization is always desirable. Over the 1971-1985 period, however, the contribution to reducing energy demand from improved efficiency is limited because of the difficulty of altering existing equipment and the long lead time before more efficient equipment can be developed and put into use. Over the longer range from 1985 to 2000, significant reduction of energy demand growth is more feasible. Since enough time would be available to permit more efficient equipment to be developed and put into use, it is possible that the lower demand level for 2000 (shown in the tabulation under the "Requirements for Energy" section above) could be achieved solely by improving efficiency in energy consumption.

- Efficiency can be increased in the use of energy both through more efficient systems and through energy conservation. Development of more efficient automotive engines could greatly increase the efficiency of energy use in the transportation sector; the average automobile engine, for example, operates at an average efficiency of less than 25 percent. The automobile itself has even less efficiency. Also, institutional changes such as increased emphasis on mass transit or urban planning that reduces commuter transportation requirements could contribute to greater efficiency in energy utilization. In the residential/commercial sector, heating and cooling energy requirements could be reduced by over one-third through improved building design and through the use of better insulation and more efficient furnaces and air conditioners.

- The most significant changes in energy use are expected to occur in the industrial sector, where (a) wider use of nuclear fuels for generation of electricity or directly for providing process heat will occur, and (b) the use of synthetic oil and gas may increase as a way to effectively utilize high-sulfur coal. The latter development, which bears primarily on the generation of process steam, will mean substantially higher fuel costs, but these higher costs can be compensated for, to some degree, through the use of higher efficiency gas turbines and compact pressurized boilers, if the relevant technologies are developed.

Shift Demand to Increased Use of Coal and Nuclear

Shifting energy demand to utilize the Nation's sizable resources of uranium and coal should be a primary goal of future energy policies. Both uranium and coal resources are potentially available in such abundance that they could satisfy requirements even under very rapid demand growth assumptions.

The projection for the year 2000 already indicates a very significant trend toward the use of electric energy—from less than 25 percent of energy consumption in 1970 to perhaps 50 percent in 2000. The projected domestic oil and gas deficit could be further reduced if the Nation's abundant resources of coal and uranium can be brought into wider use. Both coal and nuclear power are by their nature oriented toward electricity generation; hence, emphasizing electricity use would help accomplish this end. Electricity use could be increased by greater reliance on electricity for home heating, by large-scale development of mass transportation systems utilizing electricity, and by fuller use of electricity for industrial purposes. All of these approaches would obviously require a significant transformation in the Nation's means of utilizing energy, but perhaps by the end of the century such a transformation may be possible. In the non-utility market, both coal and nuclear could be more fully employed for process heating within the industrial sector.

Coal has the capability of being able to undergo form transformation—from a solid to a liquid or gaseous state. By devoting the resources necessary to move coal gasification and liquefaction programs forward, coal could also supply substantial quantities of synthetics for internal combustion fuels, home-heating fuels and fuels for other purposes by the end of the century.

Increased Imported Oil and Gas

Energy imports provided 12 percent of total energy consumption in the United States in 1970. They could account for 20 percent in 1985 under the Case II assumption, or even more under supply Cases III and IV. Because of the wide range of possible supply/demand balances in the year 2000, it is pointless to speculate on the role of imports at the end of the century. If they were to comprise 15 percent of total demand under the intermediate demand case, this would represent 14 MMB/D (oil equivalent basis); if 20 percent of the total, 19 MMB/D (oil equivalent basis).

The availability of such large volumes of hydrocarbons to U.S. purchasers is by no means assured. The world's oil and gas resource base, though great, is finite, and the United States must compete with the rapidly expanding economies of other nations for the available foreign oil. Requirements for the developing countries will grow particularly rapidly as their industrialization efforts move forward. In addition to the question of physical availability of imported hydrocarbons, there are significant national security and economic considerations, including a potential burden on the U.S. balance of payments.

Augment Energy Supplies Through New Technology

In the preceding 25 years, U.S. petroleum companies deployed their skills and capital effectively throughout much of the world to find and develop the oil and gas needed by the rapidly expanding economies of the non-Communist nations. The next 25 years to the end of the century will be equally challenging for all of the Nation's energy industries. As already discussed, the task ahead will require developing new technologies for more efficient production and use of present energy fuels. It will also be important to develop new technologies that will translate novel energy concepts into practical new energy forms. Some possibilities in this area are—

- *Geothermal power* utilizes the large reservoir of thermal energy stored in the earth's crust. The known geothermal resources that are presently economic are limited and the full energy production potential from defined localized areas will probably have been developed by about 1990. Further development of geothermal energy will depend on (a) identification of additional localized geothermal energy areas, and (b) development of deep drilling methods to exploit deep geothermal areas.
- *Solar energy* represents a vast potential source of energy. It is unlikely that large-scale use of solar energy would occur until close to the end of the century because of the high cost of energy production, the intermittent nature of solar energy, the large amount of area re-

quired to collect solar energy, and the need for significant technological advances in such areas as the utilization of solar energy from orbiting satellites. Much more work of a sophisticated and fundamental nature will be required to provide a technical base for practical schemes which would utilize solar energy.

- *Thermonuclear fusion* represents a virtually limitless source of energy available from hydrogen isotopes in seawater. This energy source is a possibility by the year 2000 although there is great uncertainty about its feasibility. A large amount of scientific research and engineering effort will be required to control the fusion process.
- *Energy from refuse* is a possibility. With the advent of the fluidized bed boiler, after 1985, agricultural and municipal wastes in selected areas may be able to provide some energy. The feasibility of incineration of waste depends on a dual purpose—power generation as well as efficient waste disposal. Energy from agricultural waste suffers from the widely scattered nature of the raw material, which makes for high collection costs. Munich and San Diego are already experimenting with plants that will convert urban refuse to energy. The feasibility of burning urban waste would be increased if people were to sort combustible and noncombustible refuse prior to disposal. However, such wastes are not considered a likely major source of relatively low-cost fuel.
- *Hydrogen* could play a role as a liquid and gaseous energy form in the long-term future if economic methods for production of hydrogen can be developed. Hydrogen has clean burning characteristics and, on a limited scale, its utilization to meet transportation and residential needs has been demonstrated; however, major technological problems remain to be solved.
- *Methyl alcohol* made from coal could be developed into an economical transportation fuel after 1985, partially compensating for the dwindling supplies of petroleum. An alternative to liquefaction of foreign natural gas and transportation in specialized tankers is conversion of the gas to methanol at the source of production, and transportation of the liquid methanol in conventional ships. Use of methanol would require changes in equipment at the point of consumption. The motivation to develop a methanol industry for this purpose would need to be established soon, however.
- *Fuel cells,* utilizing natural gas, methane or methanol, are not likely to have a major impact on fuel utilization by the year 2000. The development of rugged low-cost catalysts would be required to make fuel cells competitive with other energy conversion devices. The utilization of hydrogen as a major energy source could provide the economic incentives for the use of fuel cells for the localized generation of electricity.
- *Thermionics* conversion of heat directly into electricity is not expected to be a major energy source because of high capital costs and poor reliability of such devices.

All of these ideas are appealing, but they require considerable attention to translate the concepts into practical, economic technologies. It is necessary for the Nation to begin focusing attention on such possibilities and to search for others not visualized at this time for two interrelated reasons.

Firstly, the energy industries are highly complex. Long lead times have historically existed in energy supply response to both demand and policy changes. Moreover, long lead times exist in the development of specific energy technologies. For example, the development of the breeder reactor began in earnest in the late 1940's; it is not expected to be commercially available until the late 1980's. In the absence of top national priorities and commitments, similar time lags should be expected in other new areas of development.

Secondly, any speculative projections about the role of new technology in strengthening the U.S. energy position or in alleviating upward cost pressures in the last years of the century must be qualified by the recognition that inventions cannot be forecast. It is safe to assume, however, that in the coming three decades some major developments will be made in the energy area. This judgment is supported by historical analogy. In comparing the world of 1972 with that of 1942, for example, it is clear that technological conditions are very different; a number of developments made in this 30-year period were not predicted, and the impact of these technological innovations could not be clearly foreseen. During this 30-year period, diesel engines have expanded from limited use to widespread application for railroads, trucks and buses; jet aircraft, which were only in an early stage of development in 1942, have become the predominant type of aircraft; nuclear power has been transformed from potential military weapons to economic use in electricity generation; the technology for production and transportation of oil has grown increasingly sophisticated, permitting the development of such remote areas as the North Slope of Alaska.

Because of the long lead times involved and the inability to accurately forecast technological developments, a firm public commitment to long-term domestic energy development is essential. It is first necessary to decide on the domestic fuels most amenable to expansion and the several technological areas susceptible to productive energy research and development. Then, with the establishment of sound policies and a favorable economic climate, the Country's resources can be marshaled to develop the energy supplies needed over the longer term. Because of the complex nature of the task ahead, it will be necessary to retain some flexibility in defining those technological areas that should be developed and to pursue simultaneously a number of such programs until the approach most desirable for the national well-being is clear.

Chapter Seven

Recommendations for a United States Energy Policy

Chapter Seven
Recommendations for a United States Energy Policy
(by the National Petroleum Council)

Introduction

The National Petroleum Council's studies of the outlook for energy in the United States indicate that the country's remaining energy resources are extensive although certainly production from these resources will be of higher cost than was that in the past. Thus, a large portion of the Nation's future energy needs can be met from secure domestic sources. U.S. energy resources must be developed efficiently on a basis that will permit these resources to be converted to available supply at the lowest possible cost. To accomplish this, appropriate policies or programs must permit competition to the extent practical under constant or changing social or environmental goals.

To make these resources available on a reasonable basis will require sound enabling government guidelines so the various energy suppliers of this country can set about developing the supplies to meet the Nation's energy needs. These government policies must, in an equitable manner, ensure orderly development and a stable policy climate for all forms of energy development and supply.

U. S. Energy Policy Objectives

The primary energy industries, in cooperation with the Government, are responsible for meeting the energy needs of American society, while at the same time assuring free consumer choice at the lowest costs consistent with adequacy of long-term supply, adequate environmental standards, other social goals and, most importantly, national security.

The United States is generously endowed with energy resources. It has prospered under an industrial system built primarily upon interfuel competition for the available market. This system encouraged the development of energy resources. It is essential, therefore, to retain the security and performance that this system provides to the United States.

The National Petroleum Council believes that the fundamental objectives of public policies dealing with energy should be to—

- Assure adequate supplies of secure sources of energy
- Preserve the environment in the production and use of energy
- Promote efficiency and conservation in all energy operations and uses
- Recognize that in all three of the above objectives appropriate consideration must be given to the impact of energy costs on economic welfare and progress.

Major U. S. Energy Policies

Sound enabling government guidelines are required if the various energy suppliers of this country are to develop the maximum domestic energy supplies. The following major policy views are suggested as fundamental steps to the achievement of increased U.S. energy supplies.

1. *The United States Must Adopt a National Sense of Purpose to Solve the Energy Problem.*

A long-term sense of purpose in meeting this country's energy goals must evolve similar to the national dedication to the socio-economic goals of environmental conservation and full employment. National energy policies which are subject to constant short-term changes are wholly unsuitable for industry and government planning purposes. The long lead times inherent in energy planning and development require stability of goals and policies.

In order to attain a national resolve or commitment on a sound U.S. energy posture, cooperation among Government, industry and the general public will be essential. There is a basic need for education and cooperation in developing a common understanding of the social benefit and necessity of energy usage and the realities of resource development to fulfill energy needs.

This will require continuity of policy to assure the investor confidence essential to providing the vast capital requirements needed by the domestic energy industries.

National Security

2. *The Security of the United States Is Dependent Upon Secure Supplies of Energy, and Therefore Healthy, Viable and Expanding Domestic Energy Industries Should Be Encouraged by Government.*

Attaining a high level of national self-sufficiency in the energy sector at a manageable cost should be a prime element of national policy.

Over-dependence on foreign energy sources can (a) make the United States vulnerable to threatened or actual economic sanctions and boycotts by other countries, (b) restrict U.S. international policies, and (c) adversely affect the U.S. economy by increasing balance of trade problems, decreasing government revenues and reducing employment.

3. *The Mandatory Oil Import Control Program Should Continue to Be a Fundamental Part of the National Energy Policy of the United States.*

In the interest of national security, the Government has concluded that a healthy and viable petroleum industry must be maintained. To assist in meeting this objective, the United States by a 1959 Presidential Proclamation placed a limit on petroleum import levels. As domestic energy supplies best serve the Nation's security interests, the continuation of oil import quotas is essential.

Without oil import quotas, both domestic oil and gas availablity would decline. In addition, development of synthetic fuels from domestic sources could be retarded by the lack of economic incentives to develop such energy sources and by the threat of unrestricted imports at price levels which would not yield an adequate return for producers of synthetic fuels.

The present import quotas provide protection against the dramatic adverse effects of unrestrained imports of foreign oil. These effects could take the form of sharp increases in price or even a cutoff of supply. The national cost of the import quota system is considerably less than the cost of other alternatives such as maintenance of standby production and storage capacity.

Although increased imports of oil and gas will be needed in the immediate years ahead, import control policies should aim to increase domestic supply availability over the long term. While certain aspects of the oil import quotas have been subject to criticism, the basic purposes of the system are sound.

An import program will not serve its basic national security objective if it is subjected to short-term alterations designed to achieve unrelated objectives, such as curbs on inflation. Import programs should apply equitably to all parties and should be designed to interfere as little as possible with normal economic forces and competitive relationships.

4. *Import Policies Should Be Designed to Encourage the Growth of Domestic Refining Capacity.*

The Mandatory Oil Import Program should be designed to assure refiners of adequate access to long-term crude oil supplies; otherwise, required domestic refinery construction will not be undertaken.

The import program's implementing regulations are currently fragmented and contain a growing number of special exceptions, resulting in an atmosphere of uncertainty about future regulations. This creates reluctance to commit the massive investments required for U.S. refining capacity.

Equitable distribution of import allocations and the adoption of provisions to allow the domestic refiner to compete with imported products are of prime importance.

5. *Policies for Imports, Enrichment Operations and Government Stockpile Disposal Should Continue to Encourage Growth of the Domestic Uranium Mining Industry.*

Present national policy requires that uranium used in reactors by U.S. electric utilities, and which have been enriched in U.S. government facilities, must be of U.S. origin as required to ensure that a viable domestic uranium mining industry exists. Continuation of a policy to restrict importation of uranium is necessary if uranium producers are to make the transition from supplying solely a government market to supplying a mature commercial market.

Future demand for nuclear fuel is projected to reach levels that are several times the quantities used in the past. In the long term, nuclear power will become not only the major source of electric power but also a major source of energy in the United States. Uranium resources in the United States are believed to be adequate to supply the necessary nuclear fuel. However, large investments will have to be made in exploration, mining, milling and enrichment. Investments in uranium exploration and production of uranium concentrates are unlikely to be forthcoming unless government import policy encourages suppliers to make the long-range plans and commitments necessary to minimize U.S. dependence upon foreign sources of uranium.

The program proposed by the AEC in March 1972 for operation of government enrichment facilities and disposal of the government-owned stockpile is reasonable in conjunction with present import policy if domestic uranium suppliers find economic incentives adequate to promptly initiate and maintain sharply increased uranium supply capability. However, when a condition of oversupply leads to erosion of investment in domestic supply capability, the program for disposal of the government stockpile should cease and the existing stockpile be reserved for emergency use.

Energy in the Marketplace

6. *The Federal Government Should Establish an Economic and Political Climate Which Encourages Energy Development and Competition Among Domestic Energy Suppliers.*

Competitive markets are a particularly effective mechanism for determining price levels necessary to balance energy demand and supply. The complex operation of market forces will best serve consumers and the national interest by providing energy in amounts needed and in forms preferred for environmental reasons. Market forces, if unfettered, would promote efficient use of energy and allocate resources among energy activities on an economical basis. The results of the U.S. Energy Outlook study clearly indicate that there is a substantial capability on the part of fuel suppliers to provide additional energy raw materials from domestic resources, given the opportunity and incentive to do so. To approach the full potential of U.S. energy resources indicated in this study will require the ingenuity and effort of thousands of firms, ranging from small to large, and of millions of people.

Vigorous competition in the fuels markets presumes unrestricted entry into the various energy fuels industries, subject to applicable antitrust laws. Competition is stimulated when a supplier of one fuel can provide additional capital investment, technology and management skill for the development of other fuels. Diverse talents and resources from different fuel businesses can also be blended in such important areas as research and development. This is particularly true in the case of synthetic fuels.

7. *The Field Prices of Natural Gas Should Be Allowed to Reach Their Competitive Level.*

Federal regulation has substantially reduced exploration incentives and encouraged artificial expansion of natural gas demand. Despite its superior characteristics, natural gas currently is priced less than alternative fuels because of price controls. This results in a paradoxical situation. At the wellhead, domestic natural gas prices are held to a fraction of substitutable fuel prices in the face of present and prospective major supply shortages. Such actions, concurrent with serious consideration by government agencies and industry of the importation of natural gas from foreign sources at substantially higher prices, further illustrate the inconsistencies in current regulatory policies.

The Federal Power Commission has now apparently recognized the fallacy of holding the field prices of natural gas at artificially low levels. Uncertainty and confusion generated by current methods of price regulation of natural gas, LNG imports and synthetic gas production should be eliminated by permitting the normal interplay of economic forces in the marketplace to establish proper value. Permitting market forces to work is certainly a better solution than to continue the counter-productive regulation of natural gas prices and thereby the arbitrary allocation of supplies.

Environmental Conservation

8. *A Rational Balance Must Be Achieved Between Environmental Goals and Energy Requirements.*

Standards for a better environment, taking account of the time required to effect the desired results, must be compatible with other important national goals, including full employment, reduction of poverty, further improvement in average living standards, and assurance of energy supplies at all times for health, comfort and national security.

Prompt action is now needed to eliminate the serious delays being caused by environmental issues. The dilemmas occasioned by such issues require immediate attention in every supply sector of the energy industries: nuclear, electric power, coal, oil shale, geothermal, oil and gas. For example, the following matters require immediate governmental attention.

- Minimize delays in oil and gas exploration and development, laying of pipelines, construction of deepwater terminals and new refinery construction.
- Establish effective government siting and licensing procedures for nuclear and other electric power plant construction and operation in order to eliminate undue delays.
- Accelerate development of commercially viable stack gas desulfurization technology and other means to use high-sulfur fuels.
- Establish guidelines for land restoration to ensure minimum environmental impairment in surface coal mining operations.
- Reach early agreement on what is acceptable from an environmental standpoint for the disposal of waste oil shale rock subsequent to extraction and processing.
- Resolve serious problems relating to legal issues, planning, authorization, funding and construction of large water resource projects. This is essential in order to assure water supply availability to support the maximum level of energy growth from natural resources in the western states.

The fuel suppliers are capable of operating in such a way as to satisfy reasonable demands of society with respect to the environment. Improvement programs involve large sums of capital. In reordering its priorities, the Nation must recognize the inescapable impact of added environmental costs on supplies and prices.

The role of Government should be to ascertain the effects of pollutants and to prescribe workable standards of air, water and land quality. The means whereby the standards will be achieved should be left to the creativity of diverse private initiatives. There is a necessity to simplify requisite regulatory approvals by city, county and state authorities.

Where a cooperative approach to the solution of an environmental problem would serve the public interest, the Executive Branch should clarify the extent of cooperation that is consistent with the intent of present antitrust laws and, if necessary, seek enactment of such further enabling legislation as would be advisable.

Energy Conservation

9. *Both the Government and Industry Should Continue to Promote Energy Conservation and Efficiency of Energy Use in Order to Eliminate Waste of Our Resources.*

The United States should recognize the need for conservation and efficiency in the use of energy. In the years ahead, the pace of technological advance will probably accelerate all processes of economic growth and social and institutional change. These trends will bring change in total energy development and utilization. The growth in per capita energy consumption during the past quarter of a century has created new jobs, expanded productivity, increased living standards, and provided increasing time for cultural, recreational and intellectual pursuits. Wise policies can provide the basis for continuance of these desirable objectives.

Energy producers and the U.S. Government must take positive leadership in advocating the application of advanced technology and elimination of waste to conserve valuable domestic resources. Forced reductions in energy consumption are undesirable and should be employed only on an emergency basis.

Access to U. S. Energy Resources

10. *Access to the Nation's Energy Resource Potential Underlying Public Lands Should Be Encouraged.*

The energy resources of the Nation are extensive. At least 50 percent of the Nation's remaining oil and gas potential, approximately 40 percent of the coal, 50 percent of the uranium, 80 percent of the oil shale, and some 60 percent of geothermal energy sources are located on federal lands. Government should encourage and accelerate the orderly leasing of public lands for exploration and development of energy resources by private enterprise consonant with environmental conservation goals.

Any leasing system should provide sufficient total acreage for each fuel and should schedule sales at frequent and regular intervals, so that energy suppliers can efficiently deploy their skills towards developing needed energy supplies.

The system of leasing public lands should be reviewed in the context of urgency to develop additional reserves of oil, gas, coal, uranium, oil shale and geothermal steam. An equitable system should be designed to foster and encourage exploration for the discovery of additional energy resources.

The Outer Continental Shelf Lands Act, of August 1953, has proved to be effective legislation for the exploration and leasing of the outer continental shelf of the United States. On the other hand, the administration of the Act leaves much to be desired. Administrative actions have resulted in irregular lease sale schedules, and limited acreage offerings have worked to the detriment of exploration planning, particularly in the case of less explored frontier areas.

11. *The United States Should Maintain Jurisdiction Over Exploration and Development of the Seabed Energy Resources Underlying the Continental Margins Off Its Coasts, and Urge That Other Coastal Nations Do the Same.*

The U.S. submerged continental mass between 200 meters water depth and the seaward edge of the continental margin has been described by the U.S. Geological Survey as having great potential for petroleum. Technology is presently available to permit exploration and development in areas where water depth exceeds 200 meters, and such exploration and development should be encouraged and accelerated.

Any proposed international treaty dealing with seabed mineral resources should confirm the jurisdiction of coastal nations over the exploration and development of the mineral resources of the entire submerged continental mass off their coasts. Additionally, any such treaty should provide for the security of investments made in resource development in areas of the continental margin pursuant to agreement with or license from the coastal nation.

These provisions should take the form of assurances that the terms of such agreements or licenses will be adhered to by the parties to them and that any disputes arising will be referred to an international tribunal for compulsory objective decision. Such provisions will be essential to the investor confidence needed to provide the vast capital resources for the high costs of finding and developing mineral resources in the continental margin. In addition, a convention dealing with seabeds mineral resource development beyond national jurisdiction should also provide for a regime that will encourage private investment as required to develop these resources, and that will assure a meaningful role for private enterprise, preventing an international government cartel arrangement to control production, distribution and marketing.

Energy Research and Development

12. *Energy Research and Technology Must Be Permitted to Make the Advances Necessary for the Nation's Longer Term Development of Energy Resources.*

Research into a broad range of energy related technology could provide the means to increase future energy supplies.

If research is to make its maximum contribution, energy policies must recognize that strengthened incentives for research spending are needed. Reduced profitability in the energy industries has retarded the expansion of funds available for research and development. Improved revenues are essential to a healthy and growing research effort. In addition, commitment of large amounts of capital dollars for research requires an expectation that future government policies will continue to recognize the importance of expanding research and development programs.

Historically, research expenditures by the oil and gas industry have primarily been privately funded. Other fuel suppliers, however, particularly coal and nuclear, have historically relied largely on government funding. The National Petroleum Council endorses continued reliance on private industry as the principal source of funds for oil and gas research and takes no position on the optimal way to fund research in other fuel areas.

Areas for augmenting energy supplies that require particular attention are: perfection of a stack gas control device which would permit the use of high-sulfur coal consistent with environmental standards; research on conversion of oil shale and coal into synthetic fuels; and development of advanced nuclear reactor technology.

Taxation

13. *Fiscal Policies Should Foster the Finding and Development of All Domestic Energy Resources.*

In the past, federal tax provisions applicable to primary energy raw material resources have taken into account such factors as the risks encountered in exploration, the need for commensurate rewards in case of success and the problems involved in replacing the reserves and values depleted by production. These provisions, in turn, serve to attract requisite capital into exploration and to stimulate discovery and development of primary energy resources.

Recent developments have had a contrary effect. For example, the 1969 Tax Reform Act alone placed an additional tax burden on the domestic petroleum industry of some $500 million per annum.

Fiscal policies should encourage the creation of capital requisite for increasing energy supplies and reducing costs to the consumer. Unless more effective tax provisions are devised for all energy resources, existing measures should be retained and improved.

14. *The United States Should Support Its Nationals Engaged in Energy Operations Abroad.*

The investments and operations abroad of the U.S. energy industries are of great importance to the United States. The foreign producing interests of U.S. nationals provide supplies of energy to much of the Free World and will increasingly provide such supplies to the United States. The economic return from these activities represents a strong, favorable element in this country's balance of payments.

The U. S. Government should continue equitable tax treatment of U.S. investments abroad, including U.S. income tax credits for foreign income taxes paid.

These interests are deserving of the understanding and support of the Government of the United States. Our Government should continue to advocate the free flow of capital and technology to the oil producing countries but on the understanding that U.S. private investments will be equitably treated on the basis of commitments made by both the host country and the U.S. investor.

Concluding Recommendation

15. *The Federal Government Should Coordinate the Many Competing and Conflicting Agencies Dealing with Energy.*

Much of the confusion and delay that now plagues energy suppliers stems from conflicts among government agencies. All too often one agency may encourage an action while another agency prohibits it. Coordination of federal energy policies in the Executive Branch is necessary to provide focused, consistent guidance on energy matters to ensure that the Nation's vital needs are met.

Appendices

Appendix 1

C
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UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

January 20, 1970

Dear Mr. Abernathy:

A number of events affecting basic policies of government and the social and physical environment of this Nation have occurred or appear imminent which will set the stage for a new era in the petroleum industry in the United States. These events will have a decided impact on the Nation's resource capability and the structure of the industry.

Because of the important and pervasive nature of the changes which may be engendered by these events, there is need for an appraisal of their impact on the future availability of petroleum supplies to the United States. The long-range planning and investments to sustain the petroleum industry requires that the appraisal be projected into the future as near to the end of the century as feasible.

Therefore, the Council is requested to undertake a study of the petroleum (oil and gas) outlook in the Western Hemisphere projected into the future as near to the end of the century as feasible. This appraisal should include, but not necessarily be limited to, evaluation of future trends in oil and natural gas consumption patterns, reserves, production, logistics, capital requirements and sources, and national policies, and their implications for the United States. This should draw upon National Petroleum Council studies such as those relating to geological provinces, manpower, technology, ocean mineral resources and pollution, as well as other studies that will become available from Government agencies and industry. The Council's final report should indicate ranges of probable outcomes where appropriate and should emphasize areas where Federal oil and gas policies and programs can effectively and appropriately contribute to the attainment of an optimum long-term national energy posture.

Sincerely yours,

/s/ HOLLIS M. DOLE
Assistant Secretary of the Interior

Mr. Jack H. Abernathy
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

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UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

August 31, 1970

Dear Mr. Brockett:

I am writing to express my interest in seeing that the energy studies being done by both Dr. McKetta and the National Petroleum Council be continued.

As requested in Assistant Secretary Dole's letter of January 20, 1970, I wish to have the NPC continue on its study emphasizing oil and gas in the Western Hemisphere but taking full account of the influence of other energy forms.

I have asked Dr. McKetta to continue with his study and to report to me on all forms of energy in a parallel examination. Dr. McKetta will be calling principally upon the American Petroleum Institute for data input on oil and gas.

To coordinate the efforts of both studies, I have directed the Deputy Assistant Secretary for Mineral Resources, Mr. Gene Morrell, and my Science Adviser, D. Donald Dunlop, to meet weekly to communicate and coordinate the activities of the two groups.

I am sure that you are acutely aware of the importance of the energy problem. I look forward to the opportunity to review the results of both studies in formulating my views on a Government energy policy. Your cooperation in working with Dr. McKetta will be very much appreciated. To this end I urge that you and Dr. McKetta meet with Assistant Secretary Dole and Dr. Dunlop to discuss the objectives and working procedures of your two groups.

Best wishes for the successful completion of your work.

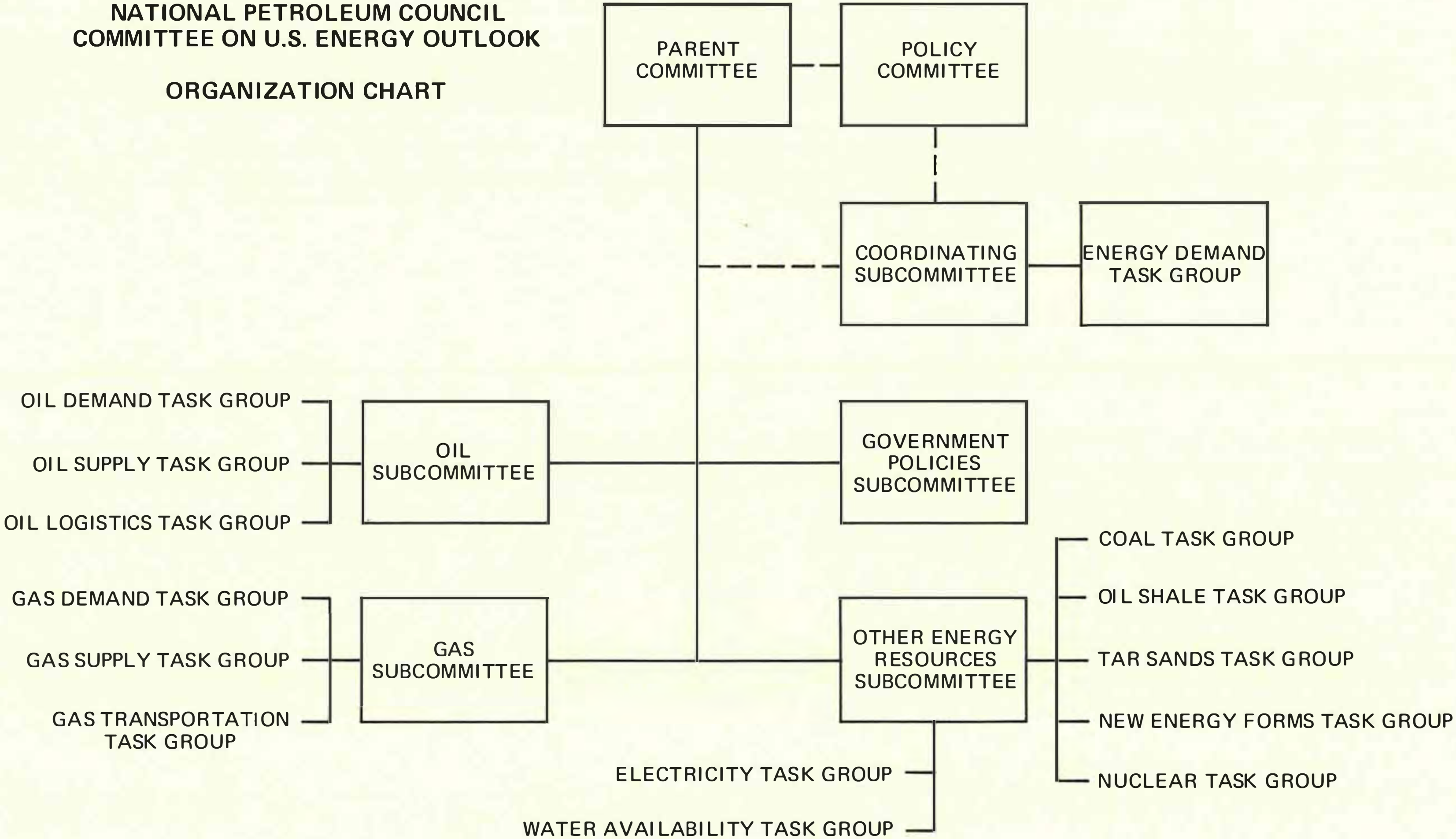
Sincerely yours,

/s/ WALTER J. HICKEL
Secretary of the Interior

Mr. E. D. Brockett, Chairman
National Petroleum Council
P.O. Box 166
Pittsburgh, Pennsylvania 15203
cc—Dr. John J. McKetta

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



Appendix 2

National Petroleum Council's
Committee on U.S. Energy Outlook

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Chairman of the Board
Continental Oil Company

Cochairman
Hon. Hollis M. Dole
Assistant Secretary-Mineral Resources
U.S. Department of the Interior

Vice Chairman, Oil
M. A. Wright
Chairman of the Board
Humble Oil & Refining Company

Vice Chairman, Gas
Howard Boyd
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D. A. McGee
Chairman of the Board
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Vice Chairman, Government Policies
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Vice Chairman, Policy Committee
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Director, Economics
Gulf Oil Corporation

Ex Officio
E. D. Brockett
Immediate Past Chairman
National Petroleum Council

Ex Officio
H. A. True, Jr.
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National Petroleum Council

Secretary
Vincent M. Brown
Executive Director
National Petroleum Council

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Big Chief Drilling Company

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M. A. Wright
Chairman of the Board
Humble Oil & Refining Company

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* Served since January 1972 replacing Charles S. Mitchell (deceased January 5, 1972).

Alternate Cochairman
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Edmond H. Farrington Consultant National Petroleum Council	Other Energy Resources
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* Replaced Henry C. Rubin—June 1972.

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Appendix 3

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Appendix 4

Additional Energy Balances

Chapter II "Energy Supply and Demand Balances," discusses the various domestic supply availability cases. This appendix contains an explanation of the balance calculations and the full detailed balances for each of 22 compilations.

For each balance, the domestic supplies of oil, gas, hydro, and geothermal were taken from the appropriate supply case. It was assumed that all of these supplies would be used. Then the oil and gas needed for electric power plus the hydro and geothermal were deducted from the electric power energy requirements that were derived from the Energy Demand Task Group's intermediate case. The remainder of the electric utility sector must be supplied by coal and nuclear.

To this subtotal of required supply of coal and nuclear for use in generating electric power was added coal requirements for other uses from the Initial Appraisal by the Coal Task Group. This total requirement for coal and nuclear was compared with coal and nuclear supply available. If the requirement was smaller than the supply, the differences entered under "Less Surplus C/N" in the balance. If the requirement is larger than the supply, the electric power sector will require increased amounts of imported oil. Where this is the case, it becomes clear that all coal and nuclear fuel supplies will be utilized.

After this adjustment was made, the supplies of various fuels were added to get the total domestic supply. Gas imports as pipeline gas, LNG and LPG were projected at their practical maximum volumes, and then it was assumed that the remaining energy requirement would be met with imported oil. Thus, imported oil is the balancing figure and required oil import volumes (converted from BTU's as crude oil) were used to measure the results of the balance.

U.S. ENERGY BALANCE TABLE 1
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—I; Gas—I; Coal/Nuclear—I; Other Energy Forms—I

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	782	1,395
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,972**	**13,145**
Balance to Coal and Nuclear	**13,055**	**21,024**	**31,218**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**26,708**	**36,910**
Less: Coal and Nuclear Available	20,650	32,549	56,910
Surplus Coal and Nuclear	**2,001**	**5,841**	**20,000**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,735	27,758	31,689
—Shale Syncrude	0	296	1,478
—Coal Syncrude	0	175	1,489
Subtotal—Oil	**20,735**	**28,229**	**34,656**
Gas—Total Production	24,513	26,746	31,604
—Nuclear Stimulation	0	206	1,341
—Coal Syngas	0	512	2,269
Subtotal—Gas	**24,513**	**27,464**	**35,214**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	782	1,395
Coal and Nuclear Required	18,649	26,708	36,910
Subtotal—Domestic Supplies	**67,007**	**86,423**	**111,495**
Total Energy Imports Required	**16,474**	**16,158**	**13,447**
Less: Projected Gas Imports	1,200	3,900	5,900
Oil Imports Required (10^{12} BTU/yr)	**15,274**	**12,258**	**7,547**
Oil Imports Required (MB/D)	**7,215**	**5,790**	**3,564**

U.S. ENERGY BALANCE TABLE 2
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**19,723**	**24,520**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**15,823**	**18,420**
Oil Imports Required (MB/D)	**7,365**	**7,474**	**8,701**

U.S. ENERGY BALANCE TABLE 3
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**26,392**	**34,926**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**22,492**	**28,526**
Oil Imports Required (MB/D)	**8,504**	**10,624**	**13,474**

U.S. ENERGY BALANCE TABLE 4
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—IV; Gas—IV; Coal/Nuclear—IV; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	16,761	24,338	36,426
Surplus Coal and Nuclear	**0**	**0**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,502	18,112	21,426
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**19,502**	**18,112**	**21,623**
Gas—Total Production	22,421	17,906	15,474
—Nuclear Stimulation	0	0	0
—Coal Syngas	0	165	494
Subtotal—Gas	**22,421**	**18,071**	**15,968**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	16,761	24,338	36,426
Subtotal—Domestic Supplies	**61,794**	**63,952**	**77,594**
Total Energy Imports Required	**21,687**	**38,629**	**47,348**
Less: Projected Gas Imports	1,200	3,900	6,600
Oil Imports Required (10^{12} BTU/yr)	**20,487**	**34,729**	**40,748**
Oil Imports Required (MB/D)	**9,678**	**16,405**	**19,248**

U.S. ENERGY BALANCE TABLE 5
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 2

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	4,110	5,350	6,480
Gas	3,250	2,600	1,950
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**19,723**	**24,520**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**15,823**	**18,420**
Oil Imports Required (MB/D)	**7,365**	**7,474**	**8,701**

U.S. ENERGY BALANCE TABLE 6
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 3

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	6,150
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,291**	**12,081**
Balance to Coal and Nuclear	**14,165**	**22,705**	**32,282**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,389**	**37,974**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**0**	**1,244**	**8,663**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	19,554	28,389	37,974
Subtotal—Domestic Supplies	**67,594**	**84,158**	**100,752**
Total Energy Imports Required	**15,887**	**18,423**	**24,190**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**14,687**	**14,523**	**18,090**
Oil Imports Required (MB/D)	**6,937**	**6,860**	**8,545**

U.S. ENERGY BALANCE TABLE 7
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 4

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	6,515	13,481	16,043
Gas	1,950	975	0
Subtotal	**11,575**	**18,097**	**20,024**
Balance to Coal and Nuclear	**11,950**	**14,899**	**24,339**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,583**	**30,031**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**2,010**	**9,050**	**16,606**

Import Requirement Calculations

	1975	1980	1985
Total U. S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	17,544	20,583	30,031
Subtotal—Domestic Supplies	**65,584**	**76,352**	**92,809**
Total Energy Imports Required	**17,897**	**26,229**	**32,133**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,697**	**22,329**	**26,033**
Oil Imports Required (MB/D)	**7,887**	**10,548**	**12,297**

U.S. ENERGY BALANCE TABLE 8
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 5

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	5,215	11,856	2,050
Gas	3,250	2,600	1,950
Subtotal	**11,575**	**18,097**	**7,981**
Balance to Coal and Nuclear	**11,950**	**14,899**	**36,382**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,583**	**42,074**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**2,010**	**9,050**	**4,563**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	17,544	20,583	42,074
Subtotal—Domestic Supplies	**65,584**	**76,352**	**104,852**
Total Energy Imports Required	**17,897**	**26,229**	**20,090**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,697**	**22,329**	**13,990**
Oil Imports Required (MB/D)	**7,887**	**10,548**	**6,608**

U.S. ENERGY BALANCE TABLE 9
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 6

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	10,136
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,291**	**16,067**
Balance to Coal and Nuclear	**14,165**	**22,705**	**28,296**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,389**	**33,988**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**0**	**1,244**	**12,649**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	19,554	28,389	33,988
Subtotal—Domestic Supplies	**67,594**	**84,158**	**96,766**
Total Energy Imports Required	**15,887**	**18,423**	**28,176**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**14,687**	**14,523**	**22,076**
Oil Imports Required (MB/D)	**6,937**	**6,860**	**10,428**

U.S. ENERGY BALANCE TABLE 10
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 2

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	4,110	5,350	6,480
Gas	3,250	2,600	1,950
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**26,392**	**34,926**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**22,492**	**28,526**
Oil Imports Required (MB/D)	**8,504**	**10,624**	**13,474**

U.S. ENERGY BALANCE TABLE 11
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 3

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear--III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	6,150
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,233**	**11,934**
Balance to Coal and Nuclear	**14,165**	**22,763**	**32,429**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,447**	**38,121**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**0**	**0**	**3,487**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	19,554	28,071	38,121
Subtotal—Domestic Supplies	**65,184**	**77,113**	**90,346**
Total Energy Imports Required	**18,297**	**25,468**	**34,596**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,097**	**21,568**	**28,196**
Oil Imports Required (MB/D)	**8,076**	**10,188**	**13,319**

U.S. ENERGY BALANCE TABLE 12
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 4

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	6,515	13,481	16,043
Gas	1,950	975	0
Subtotal	**11,575**	**18,039**	**19,877**
Balance to Coal and Nuclear	**11,950**	**14,957**	**24,486**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,641**	**30,178**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**2,010**	**7,430**	**11,430**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	17,544	20,641	30,178
Subtotal—Domestic Supplies	**63,174**	**69,683**	**82,403**
Total Energy Imports Required	**20,307**	**32,898**	**42,539**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**19,107**	**28,998**	**36,139**
Oil Imports Required (MB/D)	**9,026**	**13,697**	**17,071**

U.S. ENERGY DEMAND TABLE 13
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 5

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	5,215	11,856	2,050
Gas	3,250	2,600	1,950
Subtotal	**11,575**	**18,039**	**7,834**
Balance to Coal and Nuclear	**11,950**	**14,957**	**36,529**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**17,544**	**20,641**	**42,221**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**2,010**	**7,430**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	17,544	20,641	41,608
Subtotal—Domestic Supplies	**63,174**	**69,683**	**93,833**
Total Energy Imports Required	**20,307**	**32,898**	**31,109**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**19,107**	**28,998**	**24,709**
Oil Imports Required (MB/D)	**9,026**	**13,697**	**11,671**

U.S. ENERGY BALANCE TABLE 14
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 6

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,000	4,050	10,136
Gas	3,250	2,600	1,950
Subtotal	**9,360**	**10,233**	**15,920**
Balance to Coal and Nuclear	**14,165**	**22,763**	**28,443**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**19,759**	**28,447**	**34,135**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**0**	**0**	**7,473**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	19,554	28,071	34,135
Subtotal—Domestic Supplies	**65,184**	**77,113**	**86,360**
Total Energy Imports Required	**18,297**	**25,468**	**38,582**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,097**	**21,568**	**32,182**
Oil Imports Required (MB/D)	**8,076**	**10,188**	**15,201**

U.S. ENERGY BALANCE TABLE 15
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—IV; Gas—IV; Coal/Nuclear—I; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	20,650	32,549	56,910
Surplus Coal and Nuclear	**2,001**	**5,250**	**18,862**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,502	18,112	21,426
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**19,502**	**18,112**	**21,623**
Gas—Total Production	22,421	17,906	15,474
—Nuclear Stimulation	0	0	0
—Coal Syngas	0	165	494
Subtotal—Gas	**22,421**	**18,071**	**15,968**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	18,649	27,299	38,048
Subtotal—Domestic Supplies	**63,682**	**66,913**	**79,216**
Total Energy Imports Required	**19,799**	**35,668**	**45,726**
Less: Projected Gas Imports	1,200	3,900	6,600
Oil Imports Required (10^{12} BTU/yr)	**18,599**	**31,768**	**39,126**
Oil Imports Required (MB/D)	**8,786**	**15,006**	**18,482**

U.S. ENERGY BALANCE TABLE 16
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—I; Gas—I; Coal/Nuclear—IV; Other Energy Forms—IV

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	191	257
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,381**	**12,007**
Balance to Coal and Nuclear	**13,055**	**21,615**	**32,356**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,299**	**38,048**
Less: Coal and Nuclear Available	16,761	24,338	36,426
Surplus Coal and Nuclear	**0**	**0**	**0**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,735	27,758	31,689
—Shale Syncrude	0	0	197
—Coal Syncrude	0	0	0
Subtotal—Oil	**20,735**	**27,758**	**31,886**
Gas—Total Production	24,513	26,746	31,604
—Nuclear Stimulation	0	206	1,341
—Coal Syngas	0	165	494
Subtotal—Gas	**24,513**	**27,117**	**33,439**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	191	257
Coal and Nuclear Required	16,761	24,338	36,426
Subtotal—Domestic Supplies	**65,119**	**82,644**	**105,328**
Total Energy Imports Required	**18,362**	**19,937**	**19,614**
Less: Projected Gas Imports	1,200	3,900	5,900
Oil Imports Required (10^{12} BTU/yr)	**17,162**	**16,037**	**13,714**
Oil Imports Required (MB/D)	**8,107**	**7,575**	**6,477**

U.S. ENERGY BALANCE TABLE 17
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	20,495	26,085	27,913
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,495**	**26,282**	**28,876**
Gas—Total Production	22,951	21,674	22,221
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,951**	**22,106**	**24,254**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**65,205**	**79,118**	**94,755**
Total Energy Imports Required	**18,276**	**23,463**	**30,187**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**17,076**	**19,563**	**23,787**
Oil Imports Required (MB/D)	**8,066**	**9,241**	**11,236**

U.S. ENERGY BALANCE TABLE 18
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Intermediate Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—II; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	102,581	124,942
Less: Domestic Supplies			
Oil—Total Liquid Production	19,889	24,160	24,910
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,889**	**24,357**	**25,873**
Gas—Total Production	24,114	24,410	26,152
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,114**	**24,842**	**28,185**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**65,762**	**79,929**	**95,683**
Total Energy Imports Required	**17,719**	**22,652**	**29,259**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**16,519**	**18,752**	**23,159**
Oil Imports Required (MB/D)	**7,803**	**8,858**	**10,939**

U.S. ENERGY BALANCE TABLE 19
(All Data x 10^{12} BTU/Year)

Parameters for Balance

High Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	105,333	130,013
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**22,475**	**29,591**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**18,575**	**23,491**
Oil Imports Required (MB/D)	**7,365**	**8,774**	**11,096**

U.S. ENERGY BALANCE TABLE 20
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Low Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—II; Gas—II; Coal/Nuclear—II; Other Energy Forms—II

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	401	661
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,591**	**12,411**
Balance to Coal and Nuclear	**13,055**	**21,405**	**31,952**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,089**	**37,644**
Less: Coal and Nuclear Available	19,554	29,633	46,637
Surplus Coal and Nuclear	**905**	**2,544**	**8,993**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	95,677	112,540
Less: Domestic Supplies			
Oil—Total Liquid Production	20,630	26,456	28,477
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**20,630**	**26,653**	**29,440**
Gas—Total Production	24,300	25,043	27,324
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**24,300**	**25,475**	**29,357**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	401	661
Coal and Nuclear Required	18,649	27,089	37,644
Subtotal—Domestic Supplies	**66,689**	**82,858**	**100,422**
Total Energy Imports Required	**16,792**	**12,819**	**12,118**
Less: Projected Gas Imports	1,200	3,900	6,100
Oil Imports Required (10^{12} BTU/yr)	**15,592**	**8,919**	**6,018**
Oil Imports Required (MB/D)	**7,365**	**4,213**	**2,843**

U.S. ENERGY BALANCE TABLE 21
(All Data x 10^{12} BTU/Year)

Parameters for Balance

High Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	105,333	130,013
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**29,144**	**39,997**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**25,244**	**33,597**
Oil Imports Required (MB/D)	**8,504**	**11,924**	**15,870**

U.S. ENERGY BALANCE TABLE 22
(All Data x 10^{12} BTU/Year)

Parameters for Balance

Low Case Energy Demand; Electricity Condition Number 1

Fuel Supply Cases: Oil—III; Gas—III; Coal/Nuclear—III; Other Energy Forms—III

Electric Utility Sector Calculations

	1975	1980	1985
Electric Utility Demand	23,525	32,996	44,363
Less: Geothermal	120	343	514
Hydroelectric	2,990	3,240	3,320
Oil	3,460	4,050	4,530
Gas	3,900	3,900	3,900
Subtotal	**10,470**	**11,533**	**12,264**
Balance to Coal and Nuclear	**13,055**	**21,463**	**32,099**
Add: Non-Utility Coal	5,594	5,684	5,692
Total Coal and Nuclear Required	**18,649**	**27,147**	**37,791**
Less: Coal and Nuclear Available	19,554	28,071	41,608
Surplus Coal and Nuclear	**905**	**924**	**3,817**

Import Requirement Calculations

	1975	1980	1985
Total U.S. Energy Demand	83,481	95,677	112,540
Less: Domestic Supplies			
Oil—Total Liquid Production	19,754	23,789	24,346
—Shale Syncrude	0	197	788
—Coal Syncrude	0	0	175
Subtotal—Oil	**19,754**	**23,986**	**25,309**
Gas—Total Production	22,766	21,041	21,049
—Nuclear Stimulation	0	103	825
—Coal Syngas	0	329	1,208
Subtotal—Gas	**22,766**	**21,473**	**23,082**
Hydroelectric	2,990	3,240	3,320
Geothermal	120	343	514
Coal and Nuclear Required	18,649	27,147	37,791
Subtotal—Domestic Supplies	**64,279**	**76,189**	**90,016**
Total Energy Imports Required	**19,202**	**19,488**	**22,524**
Less: Projected Gas Imports	1,200	3,900	6,400
Oil Imports Required (10^{12} BTU/yr)	**18,002**	**15,588**	**16,124**
Oil Imports Required (MB/D)	**8,504**	**7,363**	**7,616**

Glossary

Glossary

associated-dissolved gas—associated gas is free natural gas in immediate contact, but not in solution, with crude oil in the reservoir; dissolved gas is natural gas in solution in crude oil in the reservoir; in this report associated and dissolved gas are reported jointly as that gas produced from an oil field; the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with the crude oil (dissolved).

barrel—a liquid volume measure equal to 42 U.S. gallons.

bitumen—a general name for various solid and semisolid hydrocarbons; a native substance of dark color, comparatively hard and nonvolatile, composed principally of hydrocarbon.

breeder reactor—a nuclear reactor that produces more fissionable material than it consumes. This reactor is sometimes called the fast breeder because high energy (fast) neutrons will produce most of the fissions in current designs.

British Thermal Unit (BTU)—see box at end of Glossary.

cash bonus payment—a cash consideration paid by the lessee for the execution of an oil or gas lease by a landowner. The bonus is usually computed on a per acre basis.

coal gasification—the conversion of coal to a gas suitable for use as a fuel.

coal liquefaction (coal hydrogenation)—the conversion of coal into liquid hydrocarbons and related compounds by hydrogenation.

coastwise shipping—goods shipped from one U.S. port to another U.S. port along the same coastal region.

combined-cycle plant—a plant which utilizes waste heat from large gas turbines (driven by gases from combustion of hydrocarbon fuels) to generate steam for conventional steam turbines.

condensate—liquid hydrocarbon obtained by the combustion of a vapor or gas produced from oil or gas wells and ordinarily separated at a field separator and run as crude oil.

constant dollars—see box at end of Glossary.

conventional gas—natural gas as contrasted with synthetic gas.

conventional oil—crude oil and condensate as contrasted with synthetic oil from shale or coal.

conversion—chemical processing of uranium concentrates into uranium hexaflouride gas.

cryogenic techniques—techniques involving extremely low temperatures used to keep certain fuels in a liquid form; i.e., liquefied hydrogen, methane, propane, etc.

deadweight tonnage—the difference, in tons, between a ship's displacement at load draught and light draught. It comprises cargo, bunkers, stores, fresh water, etc.

depletion allowance—a proportion of income derived from mining or oil production that is considered to be a return of capital not subject to income tax.

distillate—the liquid obtained by condensing a vapor.

enrichment—process by which the percentage of the fissionable isotope, U_{235}, has been increased above the 0.7 percent contained in natural uranium. The United States utilizes the gaseous diffusion uranium enrichment process.

fossil fuel—any naturally occurring fuel of an organic nature, such as coal, crude oil and natural gas.

fuel cell—a cell that continuously changes the chemical energy of a fuel and oxidant to electrical energy.

fuel fabrication—the manufacturing and assembly of reactor fuel elements containing fissionable and fertile nuclear material.

gross national product (GNP)—the total market value of the goods and services produced by the

Nation before the deduction of depreciation charges and other allowances for capital consumption; a widely used measure of economic activity.

hopper car—a car for coal, gravel, etc., shaped like a hopper, with an opening to discharge the contents.

hydrocarbon fuels—fuels that contain an organic chemical compound of hydrogen and carbon.

hydrotreating—the removal of sulfur from low-octane gasoline feedstocks by replacement with hydrogen.

high-temperature gas reactor—a nuclear reactor in which helium gas is the primary coolant with graphite fuel elements containing coated particles of highly enriched uranium plus fertile thorium.

in situ—in the natural or original position; applied to a rock, soil or fossil when occurring in the situation in which it was originally formed or deposited.

ionized gas—a gas that is capable of carrying an electric current.

isotope—one of two or more atoms with the same atomic number (the same chemical element) but with different atomic weights. Isotopes usually have very nearly the same chemical properties, but somewhat different physical properties.

light-water reactor (LWR)—nuclear reactor in which water (H_2O) is the primary coolant/moderator with slightly enriched uranium fuel. There are two commercial light-water reactor types—the boiling water reactor (BWR) and the pressurized water reactor (PWR).

liquefaction of gases—any process in which gas is converted from the gaseous to the liquid phase.

liquefied natural gas (LNG)—a clear, flammable liquid both tasteless and odorless; almost pure methane.

liquefied petroleum gas (LPG)—a gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures; principal examples are propane and butane.

magnetohydrodynamics (MHD)—a branch of physics that deals with magnetohydrodynamic phenomenon (of or relating to phenomena arising from the motion of electrically conducting fluids in the presence of electric and magnetic fields).

metallurgical coal—coal with strong or moderately strong coking properties that contains no more than 8.0-percent ash and 1.25-percent sulfur, as mined or after conventional cleaning.

methanol—methyl alcohol.

methyl alcohol (CH_3OH)—a poisonous liquid, also known as methanol, which is the lowest member of the alcohol series. Also known as wood alcohol, since its principal source is the destructive distillation of wood.

non-associated gas—free natural gas not in contact with, nor dissolved in, crude oil in the reservoir.

nuclear fuel cycle—the various steps which involve the production, processing, use and reprocessing of nuclear fuels.

oil-in-place—original oil-in-place less the cumulative production.

oil shale—a convenient expression used to cover a range of materials containing organic matter (Kerogen) which can be converted into crude shale oil, gas and carbonaceous residue by heating (compare shale oil).

original oil-in-place—the estimated number of barrels of crude oil in known reservoirs prior to any production, usually expressed as "stock tank" barrels or the volume that goes into a stock tank after the shrinkage that results when dissolved gas is separated from the oil.

overburden—material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials, ores or coal, especially those deposits that are mined from the surface by open cuts.

particulate matter—any matter, except water, that exists in a finely divided form as a liquid or solid.

plutonium—a fissionable element that does not occur in nature but is obtained by exposure of U_{238} to neutrons in a reactor.

primary fuel—fuel consumed in original production of energy as contrasted to a conversion of energy from one form to another.

pumped storage—an arrangement whereby additional electric power may be generated during peak load periods by hydraulic means using water pumped into a storage reservoir during off-peak periods.

reprocessing—chemical recovery of unburned uranium and plutonium and certain fission products from spent fuel elements that have produced power in a nuclear reactor.

retort—a vessel used for the distillation of volatile materials, as in the separation of some metals and the destructive distillation of coal; also a long semi-cylinder, now usually of fire clay or silica, for the manufacture of coal gas.

royalty bidding—competitive bidding for leases in which the lease is offered to the company offering to pay the landowner the largest share of the proceeds of production, free of expenses of production.

secondary recovery—oil and gas obtained by the augmentation of reservoir energy; often by the injection of air, gas or water into a production formation.

separative work—a measure of the work required to separate U_{235} and U_{238} isotopes in the gaseous diffusion process; the basis of AEC enrichment charges.

shale oil—a liquid similar to conventional crude oil but obtained from oil shale by conversion of organic matter (Kerogen) in oil shale.

stack gas desulfurization—treating of stack gases to remove sulfur compounds.

syncrude—synthetic crude oil derived from coal or oil shale.

syngas—synthetic gas (SNG).

synthetic fuel—gaseous or liquid hydrocarbon material produced from solid or liquid carbonaceous material.

tar sands—hydrocarbon bearing deposits distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon, which is not recoverable in its natural state through a well by ordinary oil production methods.

thermionic devices—devices that convert heat into electricity by evaporating electrons from a hot metal surface and condensing them on a cooler surface. No moving parts are required.

tertiary recovery—use of heat and other methods other than fluid injection to augment oil recovery (presumably occurring after secondary recovery).

thermonuclear fusion—source of energy available from hydrogen isotopes in seawater.

thorium (TH)—a naturally radioactive element with atomic number 90 and, as found in nature, an atomic weight of approximately 232. The fertile thorium-232 isotope is abundant and can be transmuted to fissionable uranium-233 by neutron irradiation. (A naturally radioactive metal. One of its natural isotopes can be converted in nuclear reactors to a nuclear fuel.)

topping—the distillation of crude petroleum to remove the light fractions only.

unitization—joining together of several separate leases into a single lease.

unit train—a system developed for delivering coal more efficiently in which a string of cars, with distinctive markings, and loaded to "full visible capacity," is operated without service frills or stops along the way for cars to be cut in and out. In this way, the customer receives his coal quickly and the empty car is scheduled back to the coal fields as fast as it came.

uranium (U)—a radioactive element with the atomic number 92 and, as found in natural ores, an average atomic weight of approximately 238. The two principal natural isotopes are uranium-235 (0.7 percent of natural uranium) which is fissionable (capable of being split and thereby releasing energy) and uranium-238 (99.3 percent of natural uranium) which is fertile (having the property of being convertible to a fissionable material). Natural uranium also includes a minute amount of uranium-234.

uranium hexafluoride (UF_6)—a volatile compound of uranium used in the enrichment process.

uranium oxide (U_3O_8)—refers to the natural uranium concentrate in yellow cake produced from milling of uranium ore. Yellow cake generally contains approximately 80-percent U_3O_8 by weight.

work program lease—a lease which is granted to the operator who in turn agrees to perform a stipulated amount of exploratory activity on the property.

"Constant" Versus "Current" Dollars

Wherever used in this report, the terms "constant dollars" or "1970 dollars" refer to the purchasing power of the U.S. dollar in the year 1970. These terms are used to provide a measure of comparability (or common denominator) to projections of Gross National Product, costs, revenues, capital requirements and other financial data which might otherwise be distorted by varying estimates of the unpredictable factor of inflation or deflation in future years.

On the other hand, where used, the term "current dollars" refers to the purchasing power of the U.S. dollar in the year referred to (e.g., 1960, 1965, 1970), including such inflation or deflation as may have existed at that time.

To convert "constant" to "current" dollars for future years, it is necessary to apply such inflation or deflation factors as the reader deems appropriate. For example, assuming an inflation factor of 10% for the 1970-1975 period, the 1975 "current" dollar could be derived by multiplying the 1970 "constant" dollar by 1.1. Unless otherwise noted, no such conversion has been made in this report.

What Is A BTU?

A BTU is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. The BTU is a very small unit of measurement, and when one adds up large quantities of energy, one must count in large multiples of the BTU. Thus, the energy balance tables in this report are expressed in trillions (10^{12}) and quadrillions (10^{15}) of BTU's.

The BTU equivalents of common fuels are as follows:

Fuel	Common Measure	BTU's
Crude Oil	Barrel (Bbl.)	5,800,000
Natural Gas	Cubic Foot (CF)	1,032
Coal	Ton	24,000,000 to 28,000,000
Electricity	Kilowatt Hour (KWH)	3,412

Two trillion BTU's per year are approximately equal to 1,000 barrels per day of crude oil.