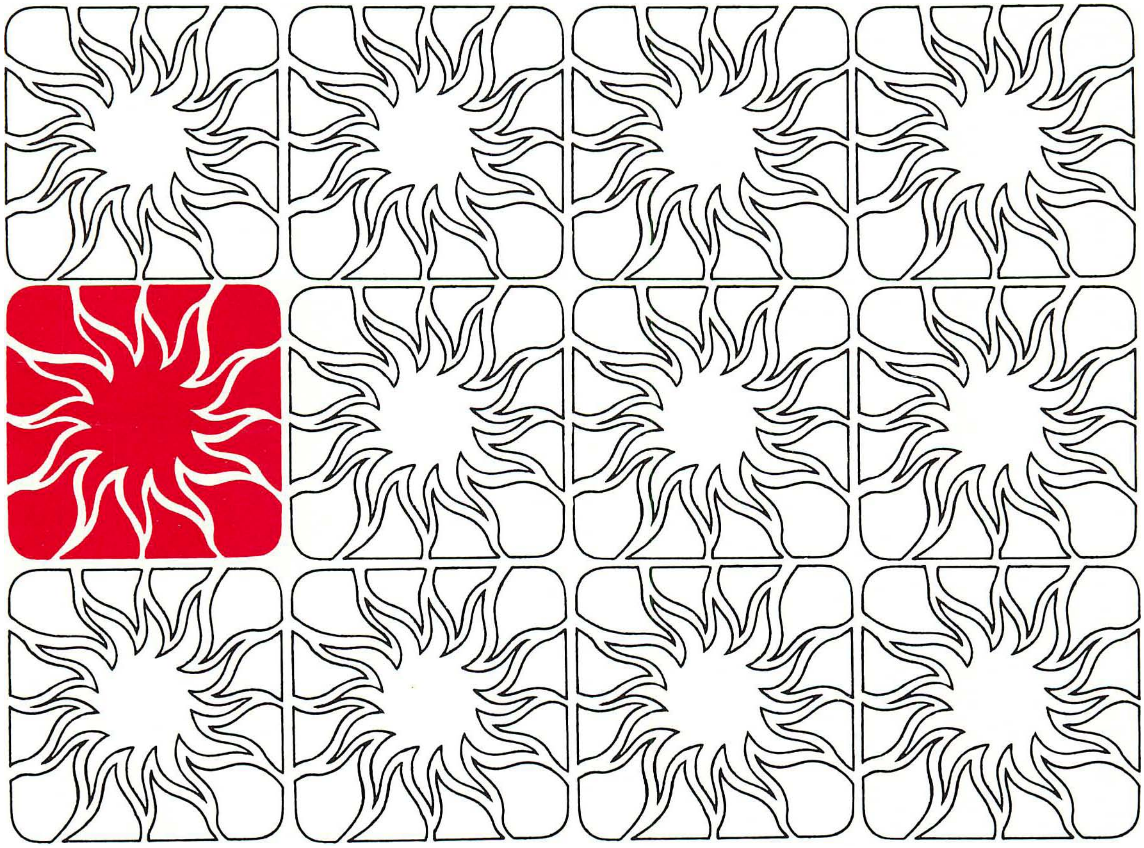
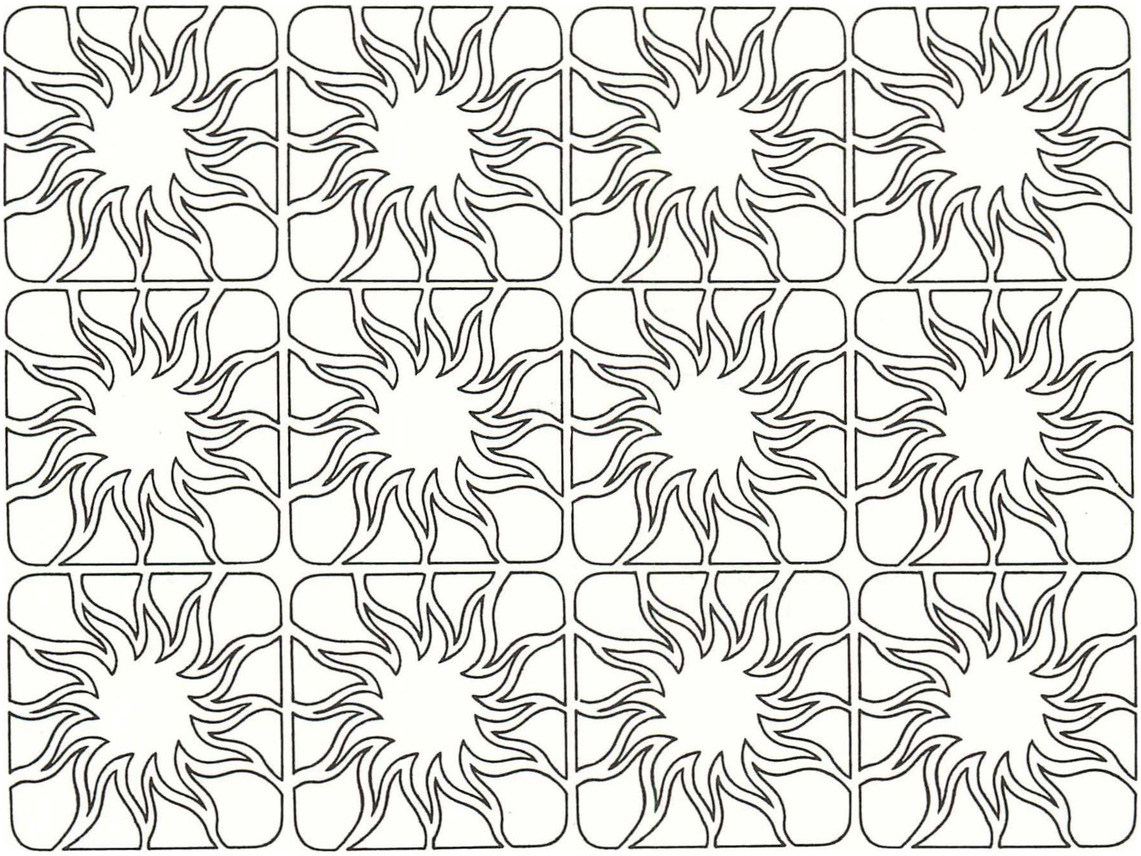


U.S. Energy Outlook

Fuels for Electricity

National Petroleum Council



U.S. Energy Outlook

Fuels for Electricity

A Report by the
Electricity Task Group of the
Other Energy Resources Subcommittee
of the National Petroleum Council's Committee
on U.S. Energy Outlook

Chairman - Jack W. Roach
Kerr-McGee Corporation

National Petroleum Council

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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 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.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and 14 task groups. An organization chart appears as Appendix 2. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal* 1971-1985 which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustrations and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Other fuel task group reports are available as listed on the order form included at the back of this volume.

The findings and recommendations of this report represent the best judgment of the experts from the energy industries. However, it should be noted that the political, economic, social and technological factors bearing upon the long-term 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.

FOREWORD

In January 1972, the National Petroleum Council's Committe on U.S. Energy Outlook established an Electricity Task Group consisting of representatives from the oil industry, Federal Power Commission, Tennessee Valley Authority, American Public Power Association, National Rural Electric Cooperative Association, Edison Electric Institute, and the investor-owned segment of the electric utility industry. The purpose of this task group was to provide the Committee on U.S. Energy Outlook with views on the electric utility industry's fuel requirements through 1985, the associated capital requirements for power plants and transmission facilities, and the relative capabilities to build and operate nuclear and fossil-fuel, steam-electric plants.

In carrying out its assignment, the task group also examined certain national and regional actions which would be beneficial to the solution of specified problems of fuel supply and utilization. Consideration was given to preparing a general policy statement which would reflect an electric utility industry position on current energy problems and their possible solutions. The task group concluded, however, that the views on certain aspects of energy policy were too diverse between the various ownership segments of the electric utility industry to make such a general statement advisable. Nevertheless, the task group did recognize that substantial areas of agreement on energy policy do exist within the total electric utility industry.

For the reader who is interested in the specific viewpoints of the various segments of the industry with regard to energy policy, it is suggested that he contact the following organizations:

American Public Power Association
2600 Virginia Avenue, N.W.
Washington, D.C. 20037

Edison Electric Institute
90 Park Avenue
New York, New York 10016

National Rural Electric Cooperative Association
2000 Florida Avenue, N.W.
Washington, D.C. 20009

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INTRODUCTION

The electric utility industry is the fastest growing major sector of the U.S. energy economy. In 1970, its primary energy requirements were exceeded only by those of the industrial sector of the economy, and by 1975 it will be the largest user of primary fuels in the Nation. Supplying these energy needs, in a manner compatible with the best interests of the electricity consumer, the environment and national security, will pose an enormous challenge to both the electric utilities and the Nation's fuel industries during the remainder of this century.

The Electricity Task Group has examined future fuel requirements from the vantage point of the electric utility industry, has studied reasonable ranges of alternatives for meeting the utilities' fuel needs, considered the implications of these alternatives, and has attempted to identify the major problem areas involved. In addition, the task group has reviewed the present and future problems of constructing steam-electric plants and attempted to illuminate the criteria which will govern plant type selection. Finally, the task group has estimated the capital investment required for the construction of generation and transmission plants which are likely to be needed.

Chapter One

PRIMARY ENERGY REQUIREMENTS OF THE ELECTRIC UTILITY INDUSTRY (1975-1985)

Projections of electricity consumption and utility primary energy requirements, as outlined in the Initial Appraisal, were reviewed by the Electricity Task Group.* It was concluded that these projections represented reasonable estimates for the period to 1985. In order to supply the total requirement of 44.4 quadrillion BTU's in 1985, several alternative fuel mixes were considered.† Four of these were selected as being feasible. The remaining two were deemed feasible but highly unlikely. All six fuel conditions are set out in Table 1.

FUEL MIX POSSIBILITIES

Condition 1

Condition 1 is considered by the task group as *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 any severe constraints on its decisions, and reflects essentially the same mix as projected by the Federal Power Commission (FPC) 1970 National Power Survey. Condition 1 assumes a lenient oil import policy and the maintenance of natural gas consumption at the 1970 level. It projects both coal and nuclear requirements, which could be met by NPC supply Case III.

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* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Two Volumes (1971).

† In addition to these alternative mixes based on the total requirements projected by the Initial Appraisal, a special "high" electricity case was developed by the Coordinating Subcommittee of the Committee on U.S. Energy Outlook. This high case is premised on an accelerated electricification of the economy in order to make use of the coal and nuclear availabilities possible under NPC supply Case I. Theoretically, realization of the high case would permit the reduction of oil imports to zero in 1985. For details, see NPC, *U.S. Energy Outlook--A Report by the National Petroleum Council's Committee on U.S. Energy Outlook* (December 1972), pp. 27-29.

‡ The Coordinating Subcommittee notes that Condition 1 is not consistent with the expectations of future gas supply as indicated by the findings of the Gas Supply Task Group.

TABLE 1

PROJECTED FUELS MIX FOR ELECTRIC UTILITIES*
(Trillion BTU/Year)

	Condition 1				Condition 2			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	3,460	4,050	4,530	220%	4,110	5,350	6,480	316%
Gas	3,900	3,900	3,900	100%	3,250	2,600	1,950	50%
Coal	8,905	14,306	13,900	180%	8,905	14,306	13,900	180%
Nuclear	4,270	7,500	18,713	7,800%	4,270	7,500	18,713	7,800%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	23,525	32,996	44,363		23,525	32,996	44,363	

	Condition 3				Condition 4			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	3,000	4,050	6,150	300%	6,515	13,481	16,043	783%
Gas	3,250	2,600	1,950	50%	1,950	975	0	
Coal	10,013	15,606	12,500	160%	7,800	7,800	7,800	10.0%
Nuclear	4,270	7,500	20,443	8,520%	4,270	7,500	17,200	7,167%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	23,525	32,996	44,363		23,525	32,996	44,363	

	Condition 5				Condition 6			
Resources	1975	1980	1985	1985 Relation to 1970 Level	1975	1980	1985	1985 Relation to 1970 Level
Oil	5,215	11,856	2,050	100%	3,000	4,050	10,136	495%
Gas	3,250	2,600	1,950	50%	3,250	2,600	1,950	50%
Coal	7,800	7,800	7,800	100%	10,015	15,606	21,457	275%
Nuclear	4,270	7,500	29,243	12,200%	4,270	7,500	7,500	3,125%
Hydroelectric	2,990	3,240	3,320	116%	2,990	3,240	3,320	116%
Total	23,525	32,996	44,363		23,525	32,996	44,363	

* Included in total supply is an estimated 500 trillion BTU's of geothermal energy for the year 1985. No attempt has been made to deduct this quantity from any of the identified fuel supplies.

Condition 2

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. This condition assumes an oil import policy at least as lenient as Condition 1.

Condition 3

Condition 3 is premised on a greater reliance on nuclear plants than are the first two conditions. However, the increased nuclear requirements can still be met under Case III assumptions. A lenient oil import policy is still considered necessary, but coal requirements are reduced as compared to Conditions 1 and 2. As in Condition 2, half of all natural gas-fired capacity is converted to oil.

Condition 4

Condition 4 is considered the least feasible of the first four conditions. It assumes severe limitations on the production and use of coal, with the result that coal consumption does not exceed the 1970 level. Nuclear development is also limited and falls below the level projected by Case III. Natural gas is completely withdrawn for power generation purposes. The result of these constraints is to drive 1985 oil consumption to 780 percent of the 1970 level. An extremely liberal import policy is thus a prerequisite for fueling the utility industry according to Condition 4.

Conditions 5 and 6

Conditions 5 and 6 are the two mixes considered feasible, but highly unlikely, by the task group. Condition 5 assumes that coal use will be held to the 1970 level for the same reasons cited in Condition 4. Half of all natural gas-fired capacity is deprived of fuel, and oil is obliged to fill a large gap in 1975 and 1980, but will fall back to its 1970 level in 1985, which would be highly improbable for both technical and commercial reasons. As a consequence, nuclear energy is required to shoulder virtually all net growth in utility requirements between 1972 and 1985. This would entail a construction program resulting in nuclear capacity approaching that projected in Case I.

Condition 6 is considered least feasible of all the conditions studied. It is predicated on a nuclear "moratorium" in effect after 1980 and the conversion of half of all gas-fired capacity to oil. Oil absorbs a considerable portion of the resulting fuel deficit and requires a liberal import policy. However, coal serves as the main "swing fuel" and rises to 275 percent of the 1970 level. To realize this degree of reliance on coal, output from the mining industry would have to approximate Case I. Also implied is near total success with 502 scrubbing and coal gasification technology, as well as a marked relaxation of environmental constraints on surface mining.

Chapter Two

RELATIVE CAPABILITIES OF THE ELECTRIC UTILITY INDUSTRY TO BUILD AND OPERATE NUCLEAR AND FOSSIL-FUEL STEAM-ELECTRIC PLANTS THROUGH 1985

In order to supply the expected increase in electric peak loads, build and maintain adequate reserve margins of generating capacity, and replace obsolete production units, the electric utility industry in the United States must install approximately 560,000 megawatts electrical generating capacity (MWe) requiring new generating facilities of all types between the end of 1972 and 1985.* It is reasonable to estimate that about 85 percent (475,000 MWe) of these gross additions will be in the form of nuclear or fossil-fuel steam plants. As of the end of March 1972, some 101,000 MW_e of nuclear plants and 90,000 MWe of fossil-fuel installation were already on firm order for 1973 and later operation. Thus, 40 percent of the new steam capacity needed during the coming 13 years has been put under contract. The balance of 284,000 MWe will be apportioned to nuclear and fossil fuel, in part, as a function of the possibilities of getting delivery of the respective plant types.

During the first half of 1971, lead times for the construction of steam power plants were estimated at 4.5 to 5.5 years for fossil-fuel installations and at 7 to 7.5 years for nuclear units in the 800 MWe to 1,100 MWe range.†

Increasing plant complexity, plus additional requirements for environmental protection statements under the National Environmental Policy Act, have added at least a year to construction lead times. Greater public participation in the planning process may also add considerably to future delays.

As a consequence, utilities planning on in-service dates of 1985 for nuclear capacity will be obliged to commit themselves before 1977. For fossil-fuel units, on the other hand, commitment decisions could be delayed until 1978 or 1979.‡ In both cases, of course, particular conditions could advance or postpone the deadline.

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* Assuming retirements equivalent to 10 percent of gross plant additions. Net additions should total about 503,000 MWe, raising installed capacity from 412,000 MWe in 1972 to near 915,000 MWe in 1985. The 1985 total is based on the FPC 1970 National Power Survey estimate of 665,000 MWe in 1980 and 6.0 percent per year growth in capacity during the 1980-1985 period.

† Robert W. Patterson, "The Sketch-Out in Power Plant Schedules," *Power Engineering* (September 1971), pp. 40-41.

‡ It should be noted that slight differences exist between the latest ordering dates indicated here and those discussed in the U.S. Energy Outlook report.

Given the lead times indicated, and assuming no greater public participation in planning, the earliest possible commissioning date for a nuclear unit ordered in mid-1972 would be late 1980. Thus, the electric utility industry may not be in the position to cover its remaining uncommitted requirements of 284,000 MWe of steam capacity entirely with nuclear plant because it would have to accept delivery of virtually all of the new capacity in the 1980-1985 period. This would not be acceptable if adequate reserve margins are to be maintained over the peak loads projected for the latter part of the 1970's. In any case, the relative delays for construction of the two types of plants are premised on both types being built.

If fossil-fuel plants were all but excluded from new ordering plans, the resulting additional burden placed on the manufacturers of components unique to nuclear stations would further extend the already lengthy lead times. Fabrication of reactor vessels could prove a particularly acute bottleneck, and the larger turbines which will still be required by low temperature/pressure, light-water reactors (LWR) could impose heavy strains on the facilities making these machines.

In view of the reduced flexibility associated with long lead times for nuclear plants, utilities are likely to reserve at least 40 percent of their projected steam plant orders for fossil fuel.* Such a strategy would have the additional advantage of providing a hedge against a marked decline in the medium-term growth rate of peak demand. This latter factor may be of particular importance since a near total dependence on plants requiring long lead time could aggravate a possible future excess capacity situation created by several years of lower than average peak load growth rates.

In addition to the key element of lead times, certain other considerations will have an influence on the electric utility industry's freedom to opt for either of the two plant types. During the 3 years 1972-1974, electric utilities have scheduled for commercial service 50 nuclear generating units totaling, some 43,000 MWe. These units will provide the industry with a substantial additional input of operating experience for large scale nuclear plants. Results of this additional experience will determine, in some cases, the degree of further commitment to nuclear generation in the subsequent 2 or 3 years. One can safely assume, however, that any negative influence stemming from the initial operation of these plants will be marginal, as the feasibility of atomic power production has already been adequately demonstrated. Each utility will merely be obliged, in light of its own particular situation, to decide to what extent it can live with startup problems.

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*This assumption would imply a maximum of 295,000 MWe of nuclear plants in service at the end of 1985 (101,000 MWe on order as of April 1, 1972, and 60 percent of the remaining 284,000 MWe of steam plant to be ordered and an estimated 22,000 MWe to be in commercial operation by December 31, 1972). This total falls just below NPC Case III for nuclear power.

In addition to the technical problems which may affect ordering plans for the balance of the 1970's, the administrative, regulatory and legal requirements for licensing both nuclear and fossil-fuel plants can be expected to become even more complex until a "one-stop" agency approval approach is established. As of mid-1972, there is hope that these procedures will be simplified, making possible a commensurate reduction in the delays involved.

Finally, the industry's freedom to rely on fossil-fuel installations for additional capacity through 1985 will depend heavily on policy decisions affecting the supply of fuels with sulfur content low enough to satisfy existing air pollution control standards and any changes in these standards likely to be made in the coming decade. Growing efforts are underway to develop technologies which will render fuel of any sulfur content acceptable for power generation. However, it is not realistic to expect that these technologies will be perfected during the coming 5 years to the point where the availability of low-sulfur fuels will no longer be a constraint on plant ordering decisions for units to be in operation by the early 1980's.

Chapter Three

INVESTMENT REQUIREMENTS THROUGH 1985

For each of the six fuel mix conditions described earlier, estimates were derived for total steam plant capital expenditures (see Table 2).

TABLE 2

PROJECTED CAPITAL INVESTMENT-1973-1985*
(Billions of Constant 1970 Dollars)

	Expenditure
Feasible	
Condition 1	148
Condition 2	150
Condition 3	153
Condition 4	136
Feasible but Highly Unlikely	
Condition 5	163
Condition 6	130

* Factors used were:

Nuclear-committed capacity @ $300/KW, uncommitted capacity @ $400/KW

Coal-committed capacity @ $220/KW, uncommitted capacity with S02 scrubbing or low-BTU gasification @ $300/KW

Oil-all capacity @ $200/KW

Natural Gas-conversion to oil @ $50/KW

It is important to point out that, while the least feasible of the six conditions discussed (Condition 6) carries the lowest investment figure, the total cost of this fuel mix condition to the economy and electricity consumers would probably 'be the greatest. Investment in mining facilities would be maximized, and the delivered price of power to the user would include high fuel costs resulting from a minimum contribution by nuclear energy.

Only the first four of the fuel mix conditions shown in Table 2 are considered probable. Capital requirements of these conditions range from $136 to $153 billion, with an average of $147 billion. For the purposes of this report, this average figure has been taken as the investment requirement for steam generating plants over the time span 1973-1985.*

* In the NPC's U.S. Energy Outlook report, investment requirements for steam plant are based on Condition 1 only.

In addition to expenditures on steam plants, the utility industry will build approximately 15 percent of its new capacity requirement in the form of internal combustion engine installations (principally gas turbines), some hydro capacity including pumped storage, and a small amount of geothermal capacity. Unit investment costs for these can vary widely--from less than $100 per kilowatt (KW) for gas turbine peaking units to several hundred dollars per KW for certain natural storage hydro plants. To estimate capital investment in these facilaities, an average weighted unit cost of $200 per KW has been assumed, implying a total investment of $17 billion.

Investment in transmission facilities necessary to deliver the output of all new generating facilities was estimated to be equivalent to about 30 percent of the investment in all production plants, a ratio which has been reasonably stable in recent years. A figure of $49 billion was thus derived which, when added to $147 billion for steam plants and $17 billion for non-steam plants, gives a total generation and transmission capital requirement of $213 billion for the 1973-1985 period.*

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* Capital expenditures for 1971 and 1972 totaled as follows (in constant 1970 dollars):

Steam Production Plant--$14 billion
Non-steam Production Plant--$2 billion
Transmission Facilities--$4 billion.

Chapter Four

ENVIRONMENTAL POLICY FACTORS BEARING ON ELECTRIC UTILITY FUEL AND PLANT DECISIONS

Possible delays in ordering and constructing power plants because of environmental, health and safety regulations can only be surmised at this time, since political and policy decisions can have a substantial effect on these delays. However, measures adopted recently are having a definite impact on plant type and fuel selection both through increased delays in equipment installation and through higher prices for fuel supplies.*

SITING OF POWER PLANTS

Siting delays encountered by utilities are aggravated by current provisions to allow public participation in all hearings, even though the thrust of the public's complaint may be of a general nature and not necessarily confined to a specific site. The ultimate effects of new regulations are unknown, but the Calvert Cliffs decision has been estimated to cause delays of 1 year or more for each nuclear plant.† The problem is further compounded by the great number of governmental agencies which claim jurisdiction. For some electric utilities, the total number of governing agencies may run as high as 70, including 2S federal agencies, many of which must be satisfied independently.

DIRECT EFFECTS OF REGULATIONS ON COSTS

Informal estimates of the impact of the Mine Health and Safety Act of 1969 indicate that considerable cost increases are being incurred by the coal mining industry. Additional costs will also be incurred to meet the environmental regulations related to coal mining, especially surface mining.

The oil and gas industries are also experiencing cost increases due to the impact of environmental regulations on the installation and operation of pipelines and refineries, the loading and off-loading of tankers, and the drilling of both exploratory and production wells offshore. These additional costs will certainly show up in the prices of oil and gas delivered to power plants.

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* An illustration of how various governmental and other factors can affect plant and fuel decisions is found in the Appendix.

† Atomic Energy Commission *vs.* Calvert Cliffs (Decided in U.S. District Court, Washington, D.C., July 23, 1971).

Finally, meeting the requirements of the Rivers and Harbors Act of 1899 will also impose additional costs on the electric utility industry and may influence plant type and fuel decisions.

The cost of delays resulting from new regulations affecting power plant licensing can be appreciable. It is estimated that, in the early 1970's, an average slippage of 1 year in nuclear plant schedules could cost the electric utility industry as much as $5 to $6 billion. The total carrying charge on the nuclear plant investment for a I-year delay could reach as much as $3 billion. The incremental increase in the cost of replacement power generated with less efficient equipment is almost $2 billion. The substitute block of steam and gas turbine capacity represents a commitment. of $6 billion by the utility industry at least 1 year earlier than would have been the case if nuclear schedules had been maintained. This is equivalent to an additional carrying charge of almost $1 billion for the year in question. The total figure of $5 to $6 billion compares to the capital expenditures of $12.5 billion in 1970, $13.4 billion in 1971, and $14.2 billion in 1972 (in constant 1970 dollars), made by electric utilities for generation transmission systems and distribution networks.

STATUS OF TECHNOLOGY

There are no stack gas sulfur removal processes in commercial operation, and there is a possibility that no process being tested today will ever be able to supply satisfactory service. Capital costs have escalated, and the limestone slurry scrubbing projects once considered low cost are now running up to $80 per KW. Moreover, the disposal problems for limestone sludge appear formidable. Any ultimate commercial applications of this process are unlikely until the later years of this decade.

Synthetic-gas-from-coal projects producing low-BTU gas should be available in the latter part of the 1970's. The commercial application in the early 1980's of these low-BTU gasification processes and the combined gas turbine/steam turbine plant with overall efficiencies as high as 50 percent will provide one major method for utilizing high-sulfur coals.

ENVIRONMENTAL IMPACT ON FUEL USAGE

While some electric utilities will continue to have natural gas as a fuel, gas-burning utilities are tending to order replacement and new oil burning units. In 1970, orders for coal burning units were markedly reduced. Switching to low-sulfur coals poses transportation, financing and burning problems. The establishment of the new coal industry in the western states could be severely compromised as state regulations, in some instances, can make even these low-sulfur coals unacceptable.

The shift to nuclear plants, clearly the most stable air pollution solution, is hindered by long lead times, higher capital investment, and the economic impact of the delays being experienced, as well as by the added costs for the control of thermal pollution.

Chapter Five

FUEL SUPPLY AND UTILIZATION PROBLEMS AS VIEWED BY THE ELECTRICITY TASK GROUP

The electric utility industry's ability to meet U.S. electric requirements, both near and long term, is being seriously impaired by a combination of four factors: (1) long nuclear plant lead times including, construction and licensing delays; (2) dwindling natural gas supplies; (3) increasingly restrictive environmental regulations; and (4) the current limitations on importation of oil.

The lead time required for the planning and construction of a nuclear plant is at least about 8 years. With the extended period required for greater public participation in planning and regulatory approval, there is little hope that lead times will be reduced.

Natural gas supplies are declining, and in most areas of the United States, electric utilities can no longer depend on supplies even for existing gas burning units. Virtually no new steam-electric generating units are now being ordered to burn natural gas exclusively.

In many areas of the country, environmental regulations have practically eliminated most types of coal as a fuel. Current technology dealing with stack-gas desulfurization systems, coal gasification, electrostatic precipitators and combustion control is not at a stage of development to permit compliance with sulfur, NO_x and particulate restrictions which are currently in effect or proposed. Consequently, the only alternatives remaining to many electric utilities are nuclear and oil fired plants. However, the nuclear alternative is available only as a long-range alternative.

Thus, in many parts of the United States, oil may be the only fuel which will enable electric utilities to meet customer requirements in an environmentally acceptable manner in the next few years. However, very little low-sulfur domestic residual fuel oil is available because the present refining pattern of the domestic petroleum industry is geared to the production of lighter end products. At the present time, there remains only one short-range fuel alternative--imported low-sulfur oil.

U.S. OIL IMPORT POLICY

The present oil import policy of the U.S. Government does not provide adequate long-term assurances that oil imports will be permitted in sufficient quantities to meet the expected new demands. While electric generating units have an expected life of about 35 years, the Oil Import Appeals Board can grant import tickets throughout much of the United States only on a year-to-year basis, with no assurance that they will be renewed.

Until environmentally acceptable domestic fuels are available in sufficient quantities, U.S. oil policy must provide access to an adequate supply of such fuels from foreign sources for a time period long enough to permit rational planning on the part of electric utilities. Moreover, any restrictions which are imposed on access to foreign fuels should not inhibit the availabilities of these fuels to electric utilities as qualified importers. The present system of granting quotas on a year-to-year basis makes it impossible for many electric utilities to make suitable arrangements to assure a long-term supply of oil for electric generating plants. This quota system makes it difficult for electric utilities to meet U.S. electric requirements, and, to the extent such requirements can be met, they will be met at higher costs.

A change in U.S. oil import policy which takes these problems into account can make a significant contribution to improving the electric utility industry's capacity to maintain reliable service in the short run. However, for the long term, government policy aimed at development of the principal indigenous U.S. fuel resources is absolutely essential in order to avoid undue dependence on imports.

U.S. SYNTHETIC HYDROCARBON DEVELOPMENT

Without question, coal and oil shale represent invaluable domestic resources which may provide alternatives to the growing dependence on foreign sources of oil and gas--a dependence which is encouraged to some extent by the convenience of liquid and gaseous fuels for medium load and peak load generating plants.

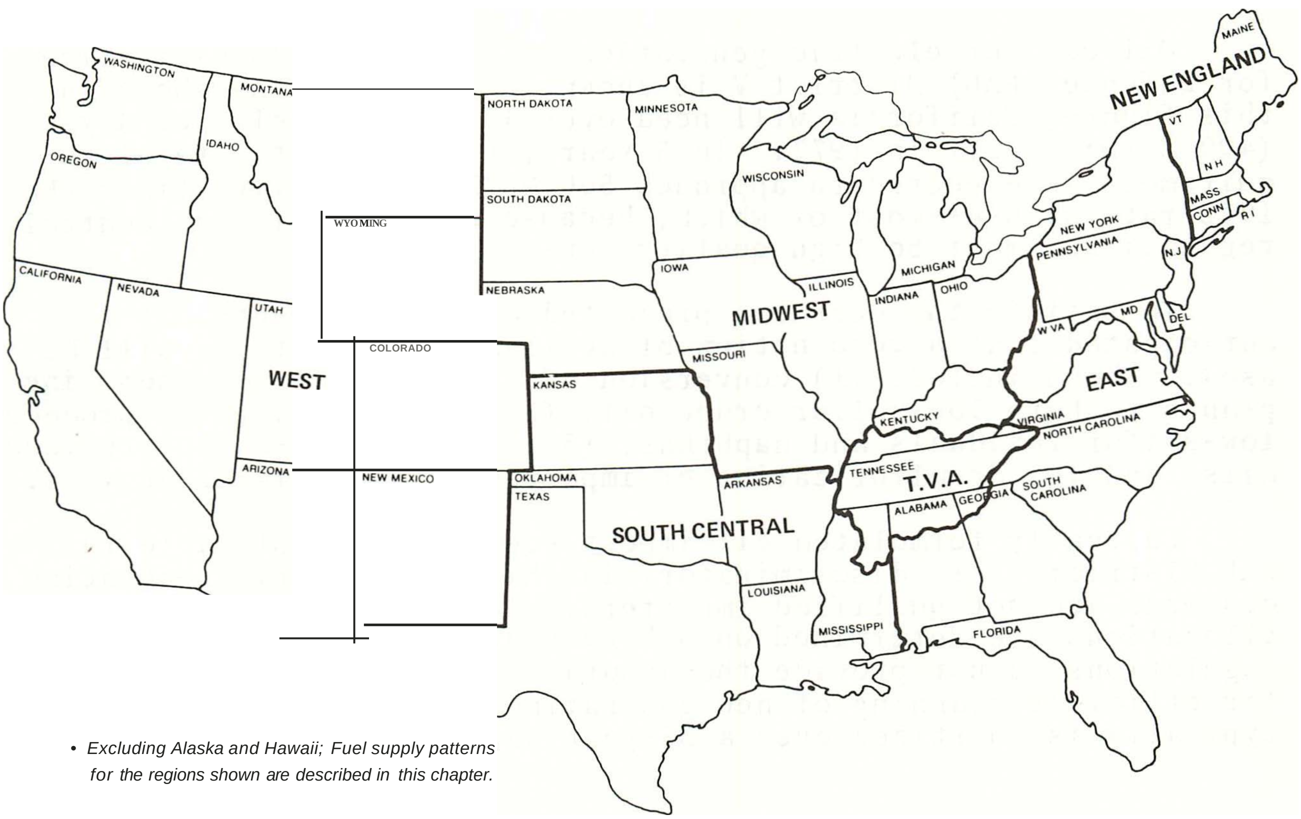
To make the fullest use of coal in an acceptable and environmentally clean manner, gasification and liquefaction will be necessary because of the flexibility of these fuel forms and because SOZ removal from stack gases may, in the long run, be handicapped by problems of residue disposal. Development of gasification and liquefaction technology, however, will require the joint efforts of the coal industry, utility industry and the Federal Government. The time lags likely to be required for perfection of these technologies demand that these joint efforts be greatly expanded.

In addition to coal, oil shale should be viewed as a potential long-range fuel source for power production. Energy supply problems of utilities in the western United States could be eased considerably after 1985 if a viable oil shale industry is created. However, government land leasing policy will affect the timing of the start of oil shale production.

Chapter Six

REGIONAL SUMMARIES OF ELECTRIC UTILITY FUEL SUPPLY AND UTILIZATION PROBLEMS

The Electricity Task Group has selected six regions which are used as a basis for a general discussion of overall fuel supply and utilization problems. These regions are: (1) West, (2) Midwest, (3) South Central, (4) TVA,* (5) East, and (6) New England. A map outlining these regions is shown in Figure 1. t



• *Excluding Alaska and Hawaii; Fuel supply patterns for the regions shown are described in this chapter.*

Figure 1. Fuel Supply Regions for Electric Utilities.*

WEST

The West region is composed of distinct subregions, each unique with respect to resources for electric generation. The Northwest has relatively abundant hydroelectric resources in conjunction with nuclear and coal generation. In the Mountain subregion (east of the coastal states), coal is the predominant re-

* Tennessee Valley Authority.

t These regions do not correspond exactly with those defined by the FPC.

source, supplemented with oil and gas fueled generation. In California, oil, natural gas, nuclear and hydroelectric energy compose the fuel mix. Alaska has abundant oil, gas and hydroelectric resources, and Hawaii is heavily dependent upon offshore oil for its electric generation requirements.

Although the aggregate raw energy reserves of the West are over 20 times greater than projected total requirements for electric generation in this century, more than half of these reserves is in the form of coal which, because of water and environmental constraints, is not expected to satisfy more than 10 percent of future energy needs. In the future, increased dependency on extra-regional fuel supplies (particularly oil) will be required from both domestic and foreign sources.

Oil use for electric generation in Petroleum Administration for Defense (PAD) District V is shown in Figure 2. As shown in this figure, California will need over 400,000 barrels per day (400 MB/D) of oil in 1977. In 5 years, the District V total requirement is expected to approach 500 MB/D--almost five times the 1972 rate of use--most of which, because of air pollution control regulatlons, must be high quality low-sulfur oils.

To satisfy the enormous projected oil requirements, it is anticipated that a combination of available alternatives will be used. These include (1) conversion of Select electric generating plants to burn low-sulfur crude oil, (2) topping plants to produce low-sulfur residuals and naphthas, (3) imported low-sulfur residual oils, and (4) desulfurization of imported or domestic crude oils.

Currently formulated oil import regulations applicable to PAD District V are discriminatory in that the electric generating concerns are not qualified importers. In addition, since import allocations are determined on a "one-year-forward" basis, these regulations do not provide the assurance and stability requlred for efficient planning of new generating capacity which, as a rule, typically is amortized over a 35-year period.

MIDWEST

In the past, electric utilities in the Midwest have relied primarily on regional coal resources to fuel their generating plants. However, the introduction of increasingly strict controls on the stack emission of S02 has rendered much midwestern coal unsuitable for power production, at least until gasification and stack gas scrubbing technologies are perfected. Other sources of low-sulfur coal exist in the West, but these fuels represent a limited alternative because of their physical and chemical characteristics. Their relatively low heat content results in a greater freight cost per BTU delivered, and problems with unburned carbon in both boilers and precipitators make the use of these coals in existing installations difficult. As a result, utilities are confronted with an acute, near-term fuel supply problem which can only be resolved through a greater reliance on fuel oil. A major switch to fuel oil is hindered, however, by administrative and logistical obstacles.

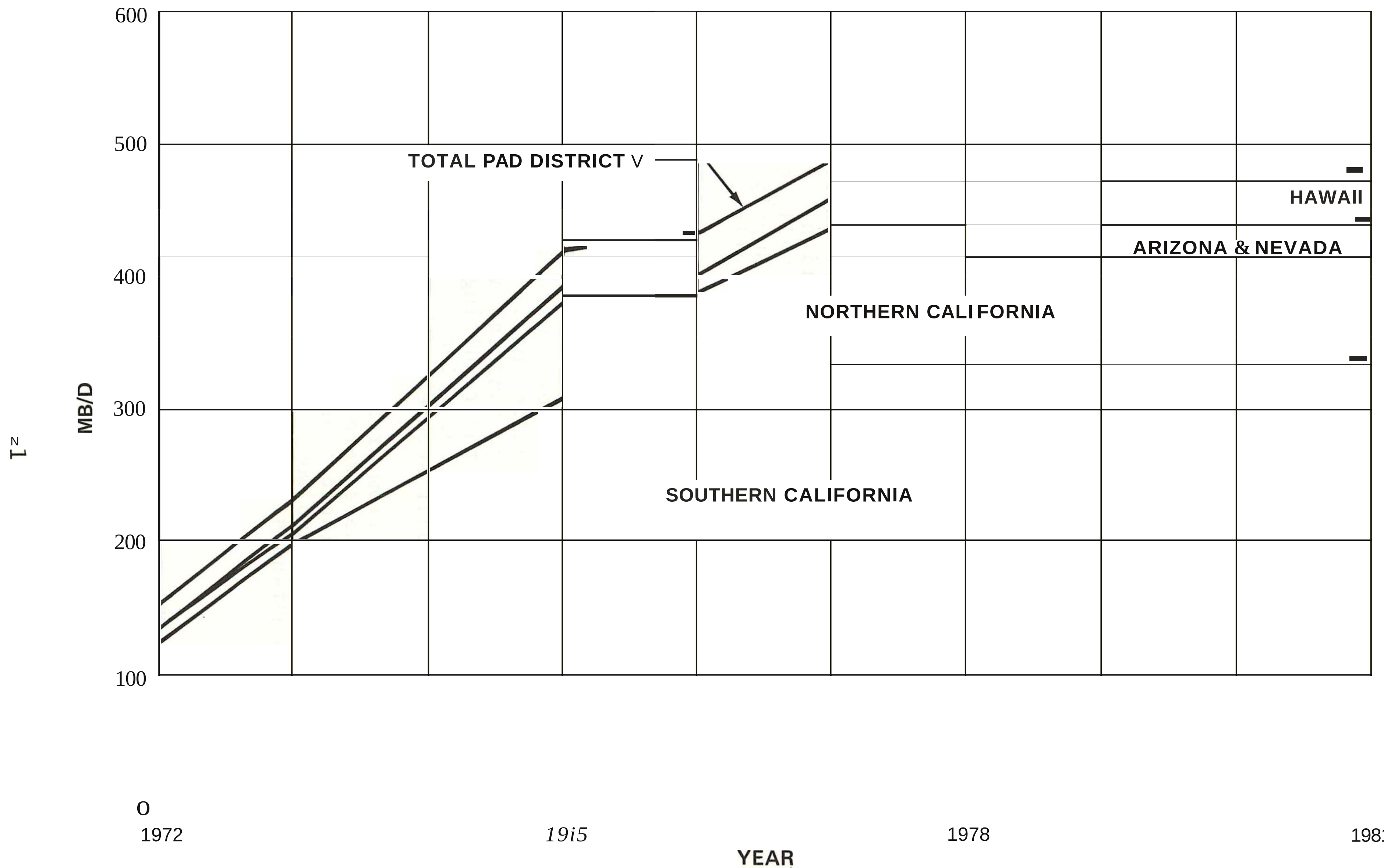


Figure 2. Estimated Fuel Oil Use for Electric Generation in PAD District V--1972-l98l.

Administrative difficulties are raised by current U.S. import and allocation policies. Since domestic supplies of low-sulfur residual fuel oil do not exist in sufficient quantities, any significant dependence on fuel oil would have to involve large imports programmed over several years. At present, such an alternative is not possible because unlimited access to foreign sources is denied to all areas of the country except PAD District I. Furthermore, those foreign supplies which are permitted to enter the interior of the United States are allocated on a year-to-year basis, with no assurance of allocation renewal. This creates extremely high operating and commercial risks for the utilities.

Logistical problems limiting any swing to fuel oil use concern pipeline and water transport facilities. Pipeline capacity certainly would be greatly overtaxed even if only a small fraction of the consumption in the Midwest were converted to oil. Water transportation offers only a partial answer, since many generating plants are not situated on navigable waterways. Further, those navigable waterways which do serve generating plants would soon be strained if all the plants located along those waterways were to be fueled by barge-delivered oil. Power stations depending on Great Lakes shipping for their oil supplies would face many additional problems, principally the need to have expensive fuel storage facilities for up to 5 months' consumption in order to compensate for the annual winter halt in navigation. In view of the present situation, Midwest utility companies will be able to utilize oil only if they can solve the specific supply and transportation problems for the location under consideration.

Over the longer term, the Midwest will look to nuclear power for a major part of its electric energy supply. However, increasing concern over thermal pollution of the Great Lakes, which are ideal as heat sinks for power production, may make nuclear plants sited on their shores somewhat more expensive than those sited elsewhere. If low-BTU coal gasification and stack gas SO_2 removal technologies are perfected, midwestern coal can again playa significant role in meeting expanding utility requirements. Finally, if exploration for oil in the Canadian Arctic should prove up large low-sulfur resources and the resulting supplies are moved by pipeline to mid-continent areas, electric utilities in the Midwest would have an additional secure long-term option.

In the meantime, oil from areas outside North America is the obvious swing fuel. If there were an assured supply of crude or finished product with reliable transportation available to each generating plant, the demand would certainly be greater than it is under present circumstances.

SOUTH CENTRAL

The South Central area is, in general, a gas-producing area where long-term gas supply contracts have been available. Because of this fact, a substantial portion of existing and "under construction" generating capacity scheduled for operation prior to

1972 has been designed to use natural gas as the primary fuel, with provision for operation on oil in emergencies. Continuous operation of these units on oil presents serious problems insofar as availability is concerned because of excessive boiler tube failures occasioned by "hot spots" encountered while burning oil which are not encountered when burning gas for which the boilers were designed. Furthermore, units designed to burn gas as the primary fuel lose approximately 10 percent of capacity immediately when switched to oil. They lose approximately another 10 percent of capacity if they are subjected to continuous oil firing due to soot buildup on heat transfer surfaces.

Conversion from natural gas to oil as the primary fuel would involve an expensive and lengthy program since utilities would necessarily first have to install new generating capacity equal to approximately 20 percent of existing and under construction capacity to offset capacity losses mentioned above prior to instituting a gas cutback program. Otherwise, utilities would be faced with the problem of "brown-outs" and a curtailment of services.

The South Central group of investor-owned electric companies burned approximately 50 percent of the 3,900 quadrillion BTU's of natural gas consumed in the United States in electric generation in 1970. Gas fired generating capacity in the South Central area is an estimated 44 million KW. This capacity would have to be supplemented by approximately 8.8 million KW of capacity costing an estimated $1.5 billion before a complete switch-over to fuel oil could be accomplished. Such a program would take approximately 8 years to effect an orderly conversion.

The fuel oil equivalent of gas consumed in the South Central area in 1970 is almost 300 million barrels (MMB) per year, which would impose an impossible burden on the fuel oil supply capability as it now exists worldwide. This, coupled with other user demands for fuel oil, would require an orderly program of refinery and tanker construction in order to satisfy demand in the event that gas is not available.

In general, capacity under construction and committed for operation subsequent to 1974 is being designed to utilize fuels other than natural gas. Nuclear capacity is predominant in plans for long-range base-load requirements. Oil fired units are being planned for some base-load use as well as for intermediate-load operation as gas supply fades out and nuclear capacity is brought on line to cover system base loads. Oil will also play an important part in meeting peak loads, since it can be transported and stored at atmospheric pressure and requires only moderate investment in transport and storage facilities. Oil will also be important since it is not feasible to modify existing gas fired generating capacity to use any other alternate fuel.

Coal will likely playa minor role in the base-load electric generating picture in the South Central area since transportation costs, together with environmental problems, make its conventional use less competitive compared to nuclear, and since it cannot be utilized in existing plants. It may, however, play an important part in fueling peaking capacity in the period beyond 1985 if technology for liquefaction of coal results in products competitive with fuel oils.

For the South Central area through 1985, it is assumed that (1) generation requirements will double each 7 years beyond 1970 and (2) in effect, the nuclear program will result in 8.5 percent of all energy being supplied from nuclear plants in 1980 and 50 percent in 1985. (The Middle South Utilities System will generate 50 percent of its energy from nuclear plants in 1980 and in excess of 70 percent in 1985.) It is also assumed that, in 1975, natural gas consumed will drop to 83 percent of its 1970 level, 65 percent of its 1970 level in 1980, and 50 percent of its 1970 level in 1985. This type of projection brings out some startling results as shown in Table 3.

TABLE 3

FUELS CONSUMPTION FOR ELECTRICITY GENERATION
(Trillion BTU's)

	Nuclear	Gas	Oil	Total
1970	0	1,800	60	1,860
1975	60	1,640	1,420	3,120
1980	470	1,340	3,810	5,620
1985	4,000	900	3,200	8,100

Since the nuclear estimates given in Table 3 are believed to be the maximum practical for the area, and since swings in the period must be substantially covered by a combination of oil and gas, the oil figures for 1980 and 1985 could be as high as 5,150 and 4,100 trillion BTU's, respectively, if all gas were taken away from power plant usage.

TVA

When TVA built its first thermal unit in the early 1940's, coal was chosen as the fuel because large deposits of economical, utility-grade coal were available in and around the TVA service area. Alternate fuels were unavailable or significantly more expensive. The use of coal continued from 1942 until 1966 when the 3,400 MWe Browns Ferry Nuclear Plant was announced. Since 1966, plans have been made for adding a 2,600 MWe coal fired plant, three additional nuclear plants, 28 gas turbine units, and a pumped storage plant. At the end of 1972, the installed capacity of the TVA system totaled nearly 22,000 MWe, consisting of 16,400 MWe of coal fired capacity, 1,100 MWe of gas turbine capacity, and 4,300 MWe of hydroelectric capacity. One plant with 900 MWe of coal fired capacity is designed for gas and coal, and gas is supplied to the plant on a seasonal basis. The gas turbine installations are designed to use gas or oil, and gas is used during the summer months when available.

Between 1972 and 1985, approximately 23,000 MWe of capacity will be added to supply the expected increase in system load. Nuclear capacity could account for as much as 18,000 MWe to 20,000 MWe, with fossil-fueled capacity or pumped-storage peaking capacity accounting for the remainder. Generation requirements in 1985 are expected to exceed 200 billion kilowatt hours (KWH). Hydroelectric generation will supply less than 10 percent of these requirements. In addition to hydroelectric, gas, oil and nuclear fuel, over 25 million tons of coal will be used to generate the required energy.

In 1985, the present gas turbines and three-stearn units that can use gas will represent about 5 percent of the total system capacity, and the estimated output from these units will be about 2 percent of the total generation requirements. There is a critical need for this capacity in the TVA system, and the curtailment, or reduction, of gas and petroleum usage would be serious. Further, the gas turbine units and the three gas-fired stearn units are located on or near the perimeter of the TVA system where the transmission of substitute power would prove costly.

Present state standards for sulfur dioxide and fly ash emissions in the TVA area are stringent. Sulfur dioxide emission standards cannot be met with current technology if the use of high-sulfur utility-grade coals continues. Strict adherence to present standards could result in a disastrous situation for the TVA power system and for power users in the TVA service area. At this time, a successful system for removing sulfur dioxide from stack gases has not been demonstrated. To meet established deadlines for controlling emissions would require changing to low-sulfur coals which would be difficult to obtain and more expensive. Also, additional investment would be required for more pulverizers, boiler modifications and increased precipitator performance. An alternative to low-sulfur coal is low-sulfur oil. Current price trends indicate that oil would be more expensive than low-sulfur coal, and its use would require increased investment to convert units to oil fired operation and to install facilities for receiving and storing large amounts of oil.

Since TVA is heavily committed to nuclear capacity, any restrictions on the operation of nuclear plants would make it very difficult to provide a reliable power supply. Since there is no substitute fuel for nuclear plants, the only alternatives are construction of more fossil-fuel plants, purchases of power, or reduction in load.

EAST

The East region is that area including PAD District I, less New England, plus that part of Alabama not served by TVA. Although the East region has, in the past, been heavily reliant on Appalachian coal as a utility fuel, this is no longer the case. Utilities serving the coastal areas began their initial shift to oil principally for economic reasons. However, due to the imposition of strict sulfur dioxide emission regulations, even those utilities (mostly inland) for which coal remained the most economical fuel were also obliged to shift to low-sulfur oil. Unlike most other areas, however, the East region has unrestricted access to foreign oil. As a result, the primary problems of fuel supply facing electric utilities are finding adequate quantities of low-sulfur oil and dealing with possible interruptions in foreign supply.

Through the mid-1970's, severe demand strains will undoubtedly be exerted on the available supplies of low-sulfur fuel oil. Most of the low-sulfur regulations being phased into force will be operative by 1975. Already, levels of 0.5 to 1.0 percent are mandatory in many communities between New York and Virginia. Although serious efforts are being made to increase the supply of acceptable fuel oil, any event which would drive requirements above projected levels, such as further delays in nuclear schedules, could prove very disruptive. The only short-term alternative, aside from a relaxation of sulfur content regulations, would be the burning of low-sulfur crude from North and West African sources.* Current utility consumption of low-sulfur crude might well rise to more than 200 MB/D by the mid-1970's.

In the longer run, the East region as well as other regions, should see some improvement in its range of electric utility fuel supply options. The development of low-BTU gasification and/or stack gas scrubbing techniques would once again make the vast Appalachian coal fields a ready source of acceptable energy for utility purposes. An already large commitment to nuclear power will certainly show results by the early 1980's, and it must be assumed that, in the future, nuclear will continue to count heavily in the expansion plans of eastern utilities, if for no other reason than to reduce an excessive dependence on foreign fuel supplies.

Other alternatives which will exist for some utilities in the East include the possible importation of liquefied natural gas (LNG) where extremely severe sulfur controls are in force and long-term commitments for some quantities of Canadian hydropower for use by utilities just south and west of New England. The task group has concluded, however, that little hydroelectric power will be available from Canada on a long-term basis. This is due to the rapid rate of load growth in Canada. Some selected sites where interim power could be available in the 1974-1985 period include--

- Churchill Falls, Labrador
- Nelson River, Manitoba

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* Low-sulfur fuel oil is in low supply worldwide.

- Peace and Upper Columbia, B.C.
- Rupert River, James Bay, Quebec.

Power interties would allow that some power, ranging from 300 to 2,000 MWe, would be available at several locations. The Rupert River development in Quebec, which is now undergoing engineering analysis, has promise of providing electric power for the Northeast U.S. region on an interim basis starting in about 1978. Estimates indicate that the available capacity would be no more than about 2,000 MWe for an interim period starting about 1980, i.e., less than the capacity of a single large nuclear power plant. Canadian hydroelectric power would thus only provide a temporary availability of limited energy for the United States.

Finally, those utilities dependent on imported low-sulfur fuel should also have a few additional options by the late 1970's. Western European refineries operating on North Sea crude would be a source of some extra supplies. However, the supplies would be limited and probably would be required for European consumption. The development of refining capacity in the Maritime Provinces of Canada will provide an additional source of products to supplement those corning from the Caribbean.

NEW ENGLAND

In the New England region, as elsewhere, the concern for preserving ambient air quality has given rise to state legislation restricting sulfur and ash content of fuels. Essentially, these restrictions operate to outlaw coal as a utility fuel and force the Connecticut and Massachusetts utility companies into the heavy oil market.

Historically, supply reliability has been a major criterion for purchasing fuels, but at this time there is no fuel available to New England to meet its air quality standards which is fully reliable in terms of supply. Those foreign fuel supplies which are subject to disruption by political unrest, tanker unavailability, and economic pressures occasioned by foreign producers operating (at least for the present time) in consort. Since fuel oil for base load is a relative newcomer to the utility fuel market, the terms and length of contracts seem to cover the entire spectrum of agreements. It is important to note that, regardless of terms, the fuel is of foreign origin and subject to the vagaries of supply indicated.

In general, the Northeast area utilities have committed themselves to a nuclear growth pattern. Nuclear fuel is presently available and relatively secure, and its use permits New England to divorce itself from the transportation penalty costs that accrue to oil and coal. However, it is common knowledge that the nuclear expansion route has its own set of obstacles in the form of environmental, safety in licensing problems.

It should be pointed out that, although the supply reliability situation is of grave concern to the utilities, the Nation as a whole faces a similar problem in that the domestic demand for petroleum products exceeds the Nation's ability to produce such products by about 25 to 30 percent at this time.

New England's planning assumes an increased reliance on nuclear base-load plants to meet new growth, particularly after 1978. An estimate of peak loads through 1985 is shown below and indicates this anticipated growth. The peak loads for each year are calculated by assuming a straight-line growth rate of 8.05 percent. It is further assumed that the operating reserve requirement on peak will be 1.5 times the capacity of the largest installed unit. This produces a growth curve which results in the following indicated peaks (net):

- 1974--16,279 MWe
- 1980--25,903 MWe
- 1985--38,100 MWe.

The significant effect which growth has on timing of decisions to install new capacity is shown in Figure 3.

Even with the heavy nuclear commitment indicated, the fossil-fuel requirements in New England should experience continued growth. Since it is expected that this increment of fossil growth will be oil fueled, the reliability of foreign supplies will remain an important concern in the future.

Figure 3. Approximate Effect of Different Growth Rates on Base-Load Capacity Additions in the New England Region--1982-1991 (in Units of 1,000 MWe or Larger).

Chapter Seven

TRENDS TO THE YEAR 2000

Until the end of this century, the capability of the electric utilities industry to build and fuel the two basic types of generating plants will be determined, to a large extent, by technical, social and economic forces which are already identified. This capability may also be influenced to some extent by additional pressures and limitations which, as of 1972, can only be surmised.

CAPACITY REQUIREMENTS

In order to determine total installed capacity required in 2000, it was estimated that electric utilities would generate some 9.6 trillion KWH. At an average load factor of 65 percent, peak demand would equal 1,685,000 MWe*. A minimum reserve margin of 20 percent would therefore imply a minimum installed capacity of 2,020,000 MWe. To achieve this level of installed capacity (assuming retirements at historical rates), the industry will have to install some 1,230,000 MWe of new facilities between 1985 and 2000. On the assumption that base-load electricity production will still use the conventional steam cycle, a figure of 85 percent should again represent a reasonable portion of the new capacity accounted for by fossil-fuel and nuclear-steam plants. Thus, 1,045,000 MWe of such capacity would be installed in this time period.

FACTORS AFFECTING PLANT SELECTION

Among the technical problems involved in accommodating these new capacity requirements will be the finding of suitable plant sites. Environmental criteria will be of prime importance, particularly the effect of pollution control regulations on cooling water availability. Severe limitations on cooling water supplies would tend to influence plant type selection in favor of fossil-fuel plants--particularly combined-cycle units--if the nuclear choice is limited to the LWR system. This bias will be partially removed, however, if high-temperature, gas-cooled reactors (HTGR) or breeder plants, which promise efficiencies rivaling those of the best fossil-fueled steam systems, become an economically justified option.

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* The electricity production projection of 9.6 trillion KWH and the average load factor of 65 percent represent estimates made by the Electricity Task Group. The generation estimate is well in line with an independent projection made by the NPC Energy Demand Task Group which calls for 9.6 trillion KWH of electricity sales in the year 2000.

Air pollution control will continue to be a major factor in determining site feasibility. However, some optimism may be justified on this point. If current prototype development results in the form of reliable and reasonably economical SO_2 removal systems and coal gasification plants, and if projected research in NO_x abatement technology is equally successful, air pollution constraints and the problem of low-sulfur fuel supplies may cease to be important limiting factors in the expansion of fossil-fuel capacity. However, this hope could be thwarted if air pollution control regulations are continually tightened so as to render inadequate the control technology at any point in time. There also remain the potential meteorological problems created by large cooling towers which, in some instances, could serve to bias plant selection against LWR nuclear systems.*

Other problems involved in choosing plant sites and the ultimate power plant type concern fuel handling. Both coal and oil fired stations need adequate space and facilities for fuel delivery, storage and handling. Access to disposal sites is also required for ash in the case of coal and, in the future, for residues produced by sulfur removal systems. The physical and possible environmental difficulties created by such requirements could weigh against these plants being installed in many cases.

Operational limitations may also be of importance in plant type selection before the end of the century. Current economic evaluations of nuclear *vs.* fossil-fuel generation assume high load factors for nuclear stations. However, by the late 1980's, some systems will have their base-load requirements fully covered by nuclear capacity. Further installations exceeding the growth of base load would necessitate a reduction in average nuclear plant capacity factors (hours use per year), although the installation of special fossil-fueled cycling units would permit maintaining nuclear capacity factors as high as possible. If the differential between the unit investment costs for nuclear and fossil-fuel plants is still such as to require base-load operation of the former, utilities will be restrained accordingly in their ability to install

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* The question of overall site availability as a potential limitation on the development of the electric utility industry has not been treated here. It is assumed that sufficient sites will be made available, and the purpose of this discussion is to identify factors which may influence the type of plant constructed. For a detailed analysis of the problem of site adequacy, see: Office of Science and Technology, *Considerations Affecting Steam Power Plant Site Selection*, Energy Policy Staff of the Office of Science and Technology, in cooperation with Atomic Energy Commission, Department of Health, Education and Welfare, Department of the Interior, FPC, Rural Electrification Commission and TVA (December 1968).

Many of the more acute environmental problems impacting on nuclear plant sites may be avoided if the concept of offshore installations should prove viable.

nuclear capacity. However, many projections of future capital and fuel costs imply that medium-load operation of nuclear plants will be economical. Behind these projections lies the assumption that, in the future, nuclear plants will benefit from economies of scale to a greater extent than fossil-fuel systems.

In addition to considerations of the utilities' capability to site and operate the needed new capacity, it is also necessary to examine the entirely separate capability of the heavy electrical equipment and construction industries to put the plans of the electric utilities into operation. The 1,045,000 MWe of steam capacity to be installed between 1985 and 2000 has already been recognized as a minimum. Assuming that maximum unit size increases from the present 1,200 to 1,300 MWe to perhaps 3,000 MWe, the mean or average of the maximum unit size over this period would probably be in the neighborhood of 2,000 MWe. This would imply that, as a minimum, the electric utility industry would have to procure some 523 units based on maximum unit size over the 15-year period. Total annual steam installations would rise from about 55,000 MWe in the mid-1980's to over 85,000 MWe at the end of the century. With hydroelectric and internal combustion plants, the work load on suppliers would average about 65,000 MWe per year in the mid-1980's and over 100,000 MWe per year in 2000.

If one compares these installation rates with some typical rates projected for the 1970's, the long-term requirements of sufficient supplier and builder capacity would not appear to pose any insurmountable problems. According to the Edison Electric Institute (EEI), the electric utility industry will put in service some 44,000 MWe in 1972, 43,000 MWe in 1973, and 38,000 MWe in 1974.* The capabilities of suppliers and constructors will have to be increased by about 150 percent to meet the demand for new plants at the end of the 1990's.

Given the lead time available, an expansion in the necessary manufacturing facilities should not prove too difficult. Assuring adequate output on construction sites may prove to be more of a problem. A recent estimate put the number of workers in the United States with power plant construction experience at 65,000. Although the growth in unit sizes may tend to limit the number of power plant projects under construction in any given year, the size and complexity of these projects will require a sizable increase in this work force if no significant improvements in productivity are made. Because of the large increase expected in the Nation's work force over the next two decades, and because of the increased efforts to bring about a greater participation of minority groups in the skilled construction trades, the availability of skilled labor in this field may not be a limiting factor. However, failure to improve the productivity of labor might result in very serious problems. In recent years, construction has been subjected to especially heavy inflationary pressures. If these pressures persist, the

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* EEI, *51st Semi-Annual Electric Power Survey* (April 1972).

electric utility industry will be affected to a greater extent than most sectors of the economy because it is one of the largest purchasers of the construction industry's services.

Improved standardization of design, building techniques and management of field labor could contribute to an overall increase in construction productivity of both fossil-fueled and nuclear plants. Since industry is still moving up on the learning curve for nuclear plants, the probability of productivity improvement on these projects is greater than on fossil-fuel stations. Offsetting these hopes for nuclear plants is the fact that breeder reactor construction has not yet started, and there will certainly be learning difficulties associated with the operation of these systems. Also, nuclear plant suppliers and builders may not always reserve their skills for the electric utility industry. The development of nuclear heat sources for industrial application could compete for some of the manufacturing and construction capacity that would otherwise be completely available to meet the demands of electricity producers.

Some positive factors exist which could help to ease any strains which might affect the manufacturers of electrical equipment because of the growth of nuclear requirements. For example, the introduction of high efficiency nuclear stearn systems (e.g., breeder) should lead to a reduction in the machine size per KW of stearn turbines as compared to those required by LWR systems, and some increase in effective production capacity of manufacturers should result. Similar improvements can be expected in other nuclear plant components, such as reactor vessels with an equivalent benefit for their fabricators. On balance, it would appear that potential productivity improvements at the manufacturing facility, as well as on the construction site, would tend to be greater for nuclear than for fossil-fuel plants.

PRIMARY ENERGY REQUIREMENTS AND GENERATION TECHNOLOGY

As noted previously, the Electricity Task Group estimates that utility generation of electric power will total nearly 10 trillion KWH in the year 2000. Fueling this production will depend heavily on nuclear power which, by that time, should account for approximately two-thirds of the industry's primary energy input. Hydroelectric generation will represent only 3 percent of total utility production. Of the remaining 30 percent to be covered by fossil fuels, coal will be the main component and will most likely be harnessed in the form of combined-cycle generating units fed by low-BTU gas. Primary fuels converted to electricity at the end of the century will account for just under half of all primary energy consumed. However, it can be hoped that much of the excess heat released during power production will be used in other industrial and commercial applications.

Thus, the long-term fuel problems of the electric utility industry will, in effect, be focused on the development and use of nuclear power. The breeder promises to reduce the thermal efficiency handicap now associated with LWR's and to make a more effective use of fissionable fuel resources.* Success in perfecting these reactors will be an essential prerequisite to interim solutions to both the environmental and fuel supply problems of the industry.

By the close of this century, success must also be registered in the development of fusion and other unconventional generation techniques if the Nation is not to be plagued by growing problems of inadequate fuel resources and thermal emission constraints. Massive research efforts which are now being prepared by the electric utility industry will be addressed to these new techniques, and it is hoped that, within 30 years, working prototypes of fusion reactors, utility fuel cells and magnetohydrodynamic (MHD) units will become reality. However, for the remainder of this century, the conventional steam cycle seems likely to remain the backbone of utility generation.

CAPITAL REQUIREMENTS--1985, 2000

The total capital requirements needed by the electric utility industry to build its needed steam production plant between 1985 and 2000 will vary according to the mix of nuclear and fossil-fueled plants. This mix will be determined by the results of the various forces touched upon in the preceeding sections of this report. A myriad of possible ratios of nuclear to fossil-fuel installations can be conceived, depending on the relative importance assumed for each of the following factors: (1) the relative costs of energy produced by the two types of systems and (2) the highest priority use of capital available. Table 4 illustrates a hypothetical comparison of nuclear *vs.* coal fired generating costs. For estimation purposes, a range of capital requirements assuming minimum and maximum nuclear installations is sufficient.

The NPC's Nuclear Task Group has suggested a range of 740,000 MWe as a minimum and 1,140,000 MWe as a maximum for nuclear plants in service in the year 2000.† Given the estimated maximum of 295,000 MWe in service at the end of 1985, nuclear installations between 1985 and 2000 could range from 450,000 MWe to 850,000 MWe (see Table 5).‡

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* HTGR's which will be in operation between 1980 and 1985 will provide some improvement over LWR's in terms of thermal efficiency and uranium utilization.

† The maximum nuclear figure of 1,140,000 MWe would represent approximately 68 percent of the peak demand projection and would imply that average nuclear plant costs in the year 2000 would permit economic operation of some of these stations for as few as 3,500 hours per year (40 percent plant factor).

‡ Assuming no significant nuclear retirements before 2000.

TABLE 4

HYPOTHETICAL COMPARISON OF NUCLEAR AND FOSSIL-FUEL BASE-LOAD GENERATING COSTS AT 80 PERCENT (PLANT FACTOR)
(Mills per KWH--Constant 1970 Dollars)

Fixed Charges	Nuclear at $400/KW*	Fossil Fuel at $300/KWt
Return } Taxes } at 15.2% Depreciation }	8.68	6.51
Operation and Maintenance	0.30	0.28
Insurance	0.15	0.05
Fuel $0.20/MM BTU at 10,500 BTU/KWH for Nuclear and $0.60/MM BTU for Fossil at 10,000 BTU/KWH	2.10	6.00:j:
Total	11.23	12.84§

* Estimate for a LWR.

t Coal fired generating plant with stack gas desulfurization equipment at approximately $80 per KW.

‡ Fuel cost includes cost of limestone or other reactive agent used in S02 scrubbing device.

§ The fossil fuel calculation would imply a break-even fuel cost of 43.9¢/MM BTU for coal and associated limestone or other reactive agent.

TABLE 5

STEAM-ELECTRIC PLANT INSTALLATION--1985-2000
(MWe)

	Minimum	Maximum
Fossil Fuel	195,000	595,000
	Maximum	Minimum
Nuclear	850,000	450,000
Total	1,045,000	1,045,000

As an illustration of the approximate magnitude of the capital requirements and the effect of the difference between fossil and nuclear plant costs, the task group has assumed that the average nuclear unit installed will cost some $400 per KW and that the average fossil-fuel unit will cost approximately $300 per KW in constant 1970 dollars.* These estimates, which were obtained from a review of current studies on the subject, provide for S02 removal equipment or low-BTU gasification facilities in the case of fossil-fuel units and cooling tower or pond facilities for both plant types. Actual capital costs will probably be higher. See Table 6 for an illustration of steam generating plant investment.

Using the same methodology employed in Chapter Three to estimate non-steam generation and transmission investment up to 1985, figures of $37 and $125 billion were derived as the required capital expenditures on these respective types of facilities for the 1985-2000 period (see Table 7). Total generation and transmission investment would thus fall in the range of $521 to $560 billion over the IS-year period. For the entire 28-year span from 1972 to 2000, investment would be between $734 and $773 billion (in constant 1970 dollars).t

TABLE 6

RANGE OF TOTAL STEAM GENERATING PLANT INVESTMENT--1985-2000
(Constant 1970 Dollars)

	Minimum		Maximum	
Fossil	595 Million KW x $300/KW =	$178.5 Billion	195 Million KW x $300/KW	$ 58.5 Billion
Nuclear	450 Million KW x $400/KW	$180.0 Billion	850 Million KW x $400/KW =	$340.0 Billion
Total		$358.5 Billion		$398.5 Billion

* The assumption that the average nuclear unit will cost some $400 per KW (in constant 1970 dollars) must be considered a minimum because the Electricity Task Group has not attempted to estimate the number of breeder plants likely to be included in the nuclear total. At present, no firm estimates exist for breeder costs per KW, although breeders will probably cost more than current reactor types.

t Investment in distribution facilities has not been considered here because other task groups of the NPC study have limited calculations of capital requirements to the production and bulk transport phases of the energy supply process. It should be noted, however, that investment in distribution facilities historically has accounted for 25 to 30 percent of all electric utility capital expenditures.

TABLE 7

SUMMARY OF ESTIMATED CAPITAL REQUIREMENTS FOR GENERATION AND TRANSMISSION PLANTS--1972-2000
(Billion 1970 Dollars)

	1972-1985	1986-2000	1972-2000
Steam-Electric Plants	147	359-398*	506-545*
Other Generating Plants†	17	37	54
Total Generating Plants	164	396-435*	560-599*
Transmission Plants‡	49	125	174
Total Generating and Transmission	213	521-560	734-773

* Ranges premised on minimum and maximum nuclear installations as initially projected by NPC Nuclear Task Group in *U.S. Energy Outlook, an Interim Report, an Initial Appraisal by the Nuclear Task Group* 1971-1985 (April 27, 1972).

† The balance of new additions representing internal combustion, geothermal and all hydroelectric plants taken at a weighted average of $200 per KW, i.e., 85,000 MWe for the 1972-1985 period and 185,000 MWe for the 1985-2000 period.

‡ Transmission investment assumed to average 30 percent of production investment (30 percent of mid-point value where ranges indicated).

The magnitude of electric utility capital requirements can be appreciated when it is compared with total investment by all energy industries. Through 1985, electric utilities will make about half of all capital outlays by the energy sector. Capital-intensiveness is, of course, a characteristic of the electric utility industry, where some $4 of net investment is required for each dollar of annual revenue. In recent years, capital expenditures by the electric utility industry have accounted for nearly 15 percent of all investment in plant and equipment. To help finance these large expenditures, new issues of stocks and bonds by the investor-owned electric utilities alone accounted for some 14 percent of all personal savings in the 3-year period 1969-1971.

Financing the expenditures required by the electric utility industry in the future will depend on decisions by regulatory authorities which recognize the impact of higher costs of capital. Historically, the private sector of the industry has relied on long-term debt for 50 to 55 percent of its capital structure. The higher interest rates for long-term bonds since the late 1960's will exert a steady upward pressure on the overall embedded cost of debt to utilities for a prolonged period of time even if current rates for new capital stabilize. This fact will continue to make adequate earnings coverage of debt service a primary consideration in the industry's efforts to attract new debt capital and refund old. Realistic rates of return are also essential to the industry if it is to acquire new equity capital and be able to make a contribution to capital expansion through retained earnings.

Other financial factors which will affect the industry's capacity to meet the Nation's demands for electric energy are adequate depreciation policies and a sufficiently high savings rate on the part of the American public.

Appendices

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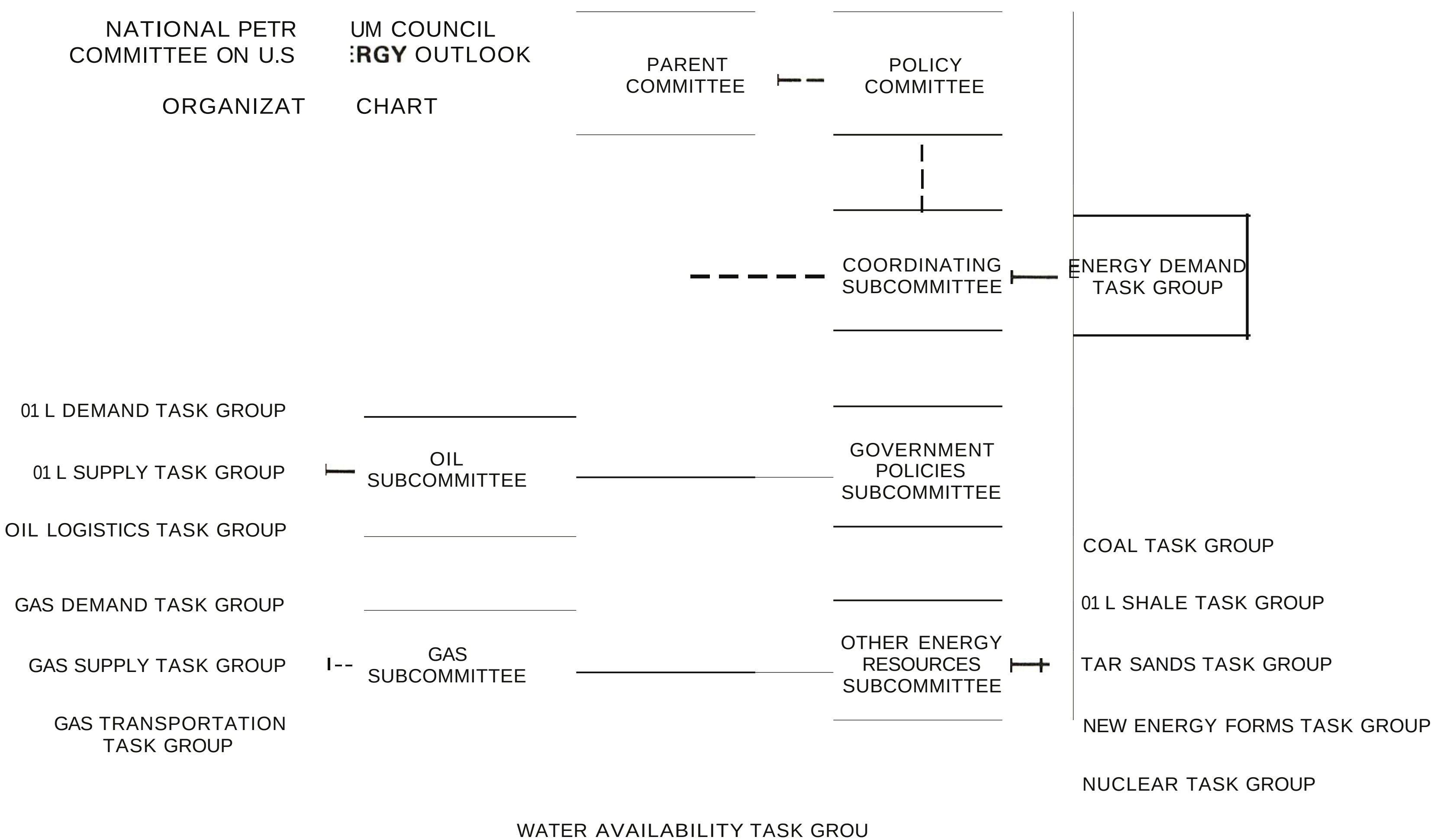

APPENDIX B

APPENDIX C

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* Served until December 15, 1972; replaced by Duke R. Ligon.

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EXAMPLE OF APPROACH TO ANALYSIS

PARAMETRIC STUDY CONDUCTED BY WESTERN SYSTEMS COORDINATING COUNCIL TO DETERMINE TIMING AND COMPOSITION OF FUTURE GENERATION RESOURCES AND FUEL MIX--

The following sample analysis is intended solely to provide an example of a type of analytical approach to the determination of the timing and composition of future generation resources and fuel mixes. It does not indicate the conclusions of the Electricity Task Group as to likely or unlikely conditions or as to the desirability of any set of conditions from the point of view of the electric utilities.

EXAMPLE OF APPROACH TO ANALYSIS

A. FEDERAL GOVERNMENT ACTION

	ASSUMED CONDITIONS		
Parameter	Case A	Case B	Case C
Coal Fired Plant Construction Moratorium	Existing moratorium terminates, no new moratorium. Moderately severe pollution regulations. Overall factors limit development of coal fired plants to 90 percent of possible locations.	Existing moratorium terminates, no new moratorium. More severe pollution regulations limit future development of coal fired plants to 75 percent of possible locations.	Existing moratorium terminates, no new moratorium. Extremely severe pollution regulations limit future development of coal fired plants to 50 percent of possible locations.
Strip Mining Regulations	Increased federal restrictions on strip mining and site restoration will result in only slightly larger amounts of planned nuclear generation. Some state standards will exceed federal restrictions. Costs associated with meeting standards will stabilize.	Restrictions on strip mining and site restoration will increase moderately. Associated cost will be correspondingly higher. Emphasis towards nuclear will only be slightly increased.	Increased restrictions and standards will result in more development of nuclear generation. Associated costs will continue to increase. Development of sites into recreational areas will gain more emphasis.
FPC Policy on Use of Gas	FPC policy will continue to discourage electric utility industry use of gas. No new gas will be certificated that is dedicated to electric utilities. Ultimately, only gas on a dump basis will be available. Policy will continue to stimulate development of coal and nuclear plants.		

Parameter	A	B	C
Uranium Available for Nuclear Plant Development	Import restrictions will be eliminated. Mine Health and Safety Acts will increase costs and affect production levels of uranium. Levels of uranium produced will permit development of all planned nuclear plants.	Import restrictions will be continued. Mine Health and Safety Acts slightly more restrictive. Production levels of uranium are further decreased. The number of nuclear plants to be developed will be reduced.	Import restrictions will be continued. Mine Health and Safety Acts become more restrictive, further increasing costs and reducing production levels. Production will allow moderate development of nuclear plants.
Oil Import Program	Continuation of the existing program.		Tariffs and quotas set to stimulate development of domestic resources, including synthetic oil or gas, at a maximum rate.
Shutdown of Existing Nuclear Plants	Operation not restricted until modifications are made but grace period set. No moratorium set on coal plants but strict pollution control regulations apply. Two-year delay in all nuclear plants being constructed. No delay on nuclear plants in design.	Operation under restricted operation until modifications are made. No moratorium set on coal plants but strict pollution control regulations apply. Two-year delay in all nuclear plants being constructed. No delay on nuclear plants in design.	Complete shutdown until able to meet criteria. Modification period two years. No moratorium on coal plants but strict pollution control regulations apply. Two-year delay in all nuclear plants being constructed. No delay on plants in design.
Five Year Moratorium on Nuclear Plants	Delays nuclear plant development; emphasis shifts for 5-year period to fossil fuel plants. Assume coal plants can be built on schedule, although under strict pollution restrictions. Operation of coal plants not delayed by legislative or legal action.	Delays nuclear plant development; moratorium terminates after 5 years. Government permits construction of coal fired plants. Severe regulation requirements limit development of coal fired plants to 75 percent of total possible development sites. Operation of coal plants not delayed.	Delays nuclear plant development; moratorium terminates after 5 years. Department of Interior permits construction of coal fired plants. Severe regulation requirements limit development of coal fired plants to 50 percent of total possible development sites. Legislative and legal activity delay operation of coal plants.
Shutdown or Restricted Operation of Existing Coal Plants	Four Corners coal fired plant operates under severe pollution restrictions until modifications made. Other coal fired plants continue to operate as previous. No restrictions on nuclear plants.	Four Corners on 50 percent of maximum output until modifications made. Other plants operate under pollution control restrictions. No restrictions on nuclear plants.	All coal fired generation in Four Corners area shutdown and all other coal fired generation restricted to 50 percent of maximum output. No restrictions on nuclear plants.

B. STATE GOVERNMENT ACTION

Parameter	A	B	C
Five-Year Moratorium on Nuclear Plants by States	Delays nuclear plant development; emphasis shifts for 5-year period to fossil-fueled plants. Assume fossil-fueled plants can be built on schedule, although under strict air pollution regulations. Operation of fossil plants not delayed by legislative or legal action.	Delays nuclear plant development; moratorium terminates after 5 years. Assume state rulings on coal plants and pollution control regulations imposed limit development of coal fired plants in state to 75 percent of possible sites. The operation of fossil type plants not delayed by legal or legislative action.	Delays nuclear plant development; moratorium terminates after 5 years. Severe pollution control regulations limit development of coal fired plants in the state by 50 percent of possible sites. Level of legislative and legal activity in the state delays the operation of fossil type plants.
Ability to Construct Necessary Transmission Lines for New Generating Plants	Utilities will still be able to construct all lines. Legislative, regulatory and legal activity against the lines will increase but will not be intolerable. Delays in operating dates may occur. All lines will be overhead construction. Technology will slightly reduce the cost of undergrounding.	Utilities will still be able to construct all lines, although lead time for some lines will have to increase due to level of legal, legislative and regulatory action. 10 to 20 percent of all 220-kV line construction will be placed underground. Cost ratio of underground to overhead will decrease to 3/1.	Utilities will still be able to construct all lines, although an increased lead time for lines will have to increase due to level of legal, legislative, and regulatory action. 30 percent of all 200-kV line construction will be placed underground. Cost ratio of underground to overhead is 3/1.
Effects of Generation Development Due to (1) State Restrictions on Coal Plants, (2) Strict County Pollution Control Regulations	Severe plant output regulations adopted by some states and adopted by all by 1980. Plants operate under restrictions but are not curtailed. Regulations similar to Rule 67 (Nitrogen Oxide Regulations) for Los Angeles Basin are adopted by all counties over IS-year period.	Severe plant output regulations adopted by some states are adopted by all by 1980. Plants operate under restrictions but are not curtailed. Regulations similar to Rule 67 (Nitrogen Oxide Regulations) for Los Angeles Basin are adopted by all counties over a 10- to IS-year period.	Plant output is reduced by 50 percent for 3 years due to state regulations until standards are met. Regulations similar to Rule 67 (Nitrogen Oxide Regulations) for Los Angeles Basin are adopted by all counties over 10-year period.

Parameter	A	B	C
Hydroelectric Power Development in Pacific North Northwest	Development of new dams permitted, but some sites are restricted. All units installed in existing dams. Appropriations of Federal funds will be limited during some periods.	Moderate development of new dams permitted, but many sites are restricted. All units installed in existing dams. Appropriations of Federal funds will be limited during some periods. Some additional thermal generation may be required.	Severely limited development of new dams. All units installed in existing dams. Appropriations of Federal funds will be limited during some periods. Additional thermal generation may be required.
C. LOCAL GOVERNMENT ACTION			
Regulatory Effect on Stack Gas Treatment Technology	Local air pollution control regulations will be revised by local agencies to permit use of stack gas treatment technology.		Slowness of action, lack of expertise, and public opinion restrict ability to change regulations.
Local Government Action on Operation of Existing Plants or Construction of New Plants	No action will be taken against existing plants. Direct action may be taken against some proposed new plants.	Restrictive regulations will be adopted against existing plants. Direct action will be taken against all proposed new plants resulting in some cases of delays of 1 to 5 years.	Some existing plants will be restricted from full-load operation until they comply with regulations. Older plants that cannot comply will eventually be phased out. Court cases and legislative activities will result in delays of 1 to 5 years for proposed plants.
Effects on (1) Siting Criteria (2) Approving or Disapproving Proposed Plants	A one-stop agency for plant approval will be established at both the state and Federal levels within 5 years. This action will reduce delays int introduced by multiple-stop agency approvals. Installation of plants on coastline will not be restricted but pressure will increase for companies to locate plants inland at isolated areas. All types of plants will be affected.	Multiple-stop agency approval for siting will continue for some time and then begin decreasing toward a one-stop agency at the state and Federal level. Multiple-stop agency approval will result in delays but plants will be approved. More public hearings and approvals will be required. Plants on coastline are at selected locations only. Pressure increases to locate plants inland. All types of plants will be affected.	A one-stop agency will not occur in the foreseeable future. **Mul-tiple-stop** agency approval will result in delays and in some cases plant rejections. More public hearings and approvals will be required. Installation on the coastline will be restricted. Increased pressure to locate plants inland. All types of plants will be affected.

D. OUTSIDE FACTORS

Parameter	A	B	C
Availability of Cooling Water	Fresh water reserved for higher priority uses. No severe restraint on regulations regarding thermal pollution of cooling water sources.	Fresh water reserved for higher priority use. More restrictions requiring cooling ponds or towers in some locations	Fresh water reserved for higher priority use. Severe restrictions on location, requiring use of cooling ponds or towers.
Feasibility of Dry Type Cooling	Insufficient supply of cooling water of plants increases the need for dry type cooling. Sufficient area is available for the site. Aesthetic considerations are acceptable for the large towers.		
Development of Thermal Generation in Pacific Northwest	Approval to construct nuclear and fossil plants will be obtained. Seismic criteria will be reasonable. Sufficient fossil fuels will be obtained.	Approval to construct obtained but only 50 percent of sites finally developed. Legislative and legal activity result in delays of I to 2 years.	Approval to construct gained but only 50 percent of sites finally developed. Legislative and legal activity result in delays of 3 to 5 years. Seismic criteria restrictive in some cases.
Development of Thermal Generation in Pacific Northwest for Power for Pacific Southwest	Same as above, except Pacific SW utilities are allowed to participate to extent of 8,000 MW over next 20 years. Transmission lines associated with the project are approved.	Same as above, except Pacific SW utilities are allowed to participate to extent of 5,000 MW over next 20 years. Transmission lines associated with the project are approved.	Same as above, except Pacific SW utilities are allowed to participate to extent of 5,000 MW over next 20 years. Transmission lines associated with the project are approved.
Effects of Cost Escalation on Construction of Plants	Inflation trends continue but present high trend is controlled. Cost of construction for both fossil and nuclear plants will escalate at a compound annual rate of 3.2 percent over next 30 years. Rate will not influence the type of plant or number built.		

Parameter	A	B	C
Development of Geothermal Power	Exploration will develop some usable resources to provide approximately 5 percent of the total generation in Pacific Southwest by 1985. Technology will permit economic treatment of natural steam for conversion to clean steam.		
Development of Magnetohydro-dynamics or Breeder Reactors	No commercial development of magnetohydrodynamics resources will occur prior to 1990. Between 1990 and 2000 commercial units no larger than 100-200 MW will be available. No commercial breeder reactor will be in service prior to 1983. Additional breeders will not come on line until 1985 and a range of both slow and moderate development through 2000 should be assumed.		

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