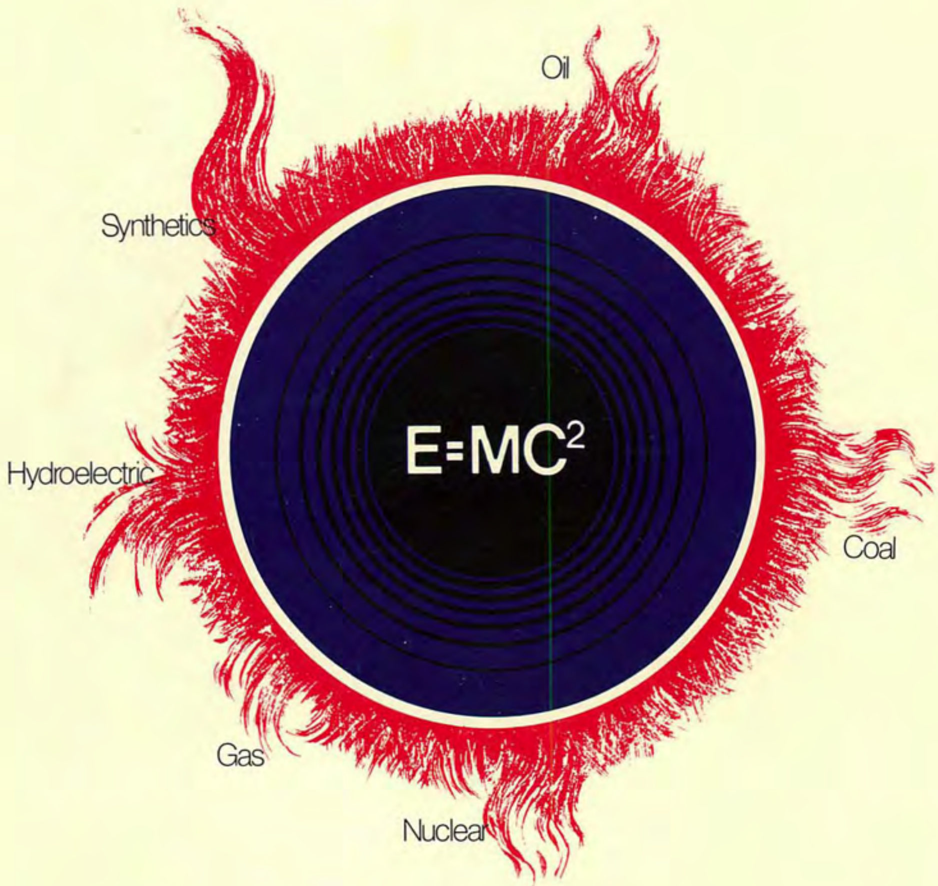
U.S. Energy Outlook

An initial appraisal 1971-1985



VOLUME TWO
Summaries of Task Group Reports
November 1971

An Interim Report
of the
National Petroleum Council

U.S. ENERGY OUTLOOK:
AN INITIAL APPRAISAL 1971-1985

VOLUME TWO
Summaries of Task Group Reports

November 1971

An Interim Report
Prepared by the
National Petroleum Council's
Committee On U.S. Energy Outlook

Chairman—John G. McLean

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U.S. ENERGY OUTLOOK

AN INITIAL APPRAISAL (1971-1985)

VOLUME TWO

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P R E F A C E

This is Volume Two of a two-volume interim report prepared by the National Petroleum Council, representing an initial appraisal of the energy outlook of the United States. Volume One of the interim report, dated July 15, 1971, projects supply/demand relationships for the period 1971-1985, assuming minimal changes in the economic climate of the energy industries and in government policies and regulations concerning those industries. An extract from Volume One appears herein.

Volume Two of the interim report contains summaries of the reports made by the various fuel task groups. These summaries were developed after extensive work on the initial appraisal. Complete task group reports will be made available throughout the fall of 1971.

The contents of both Volumes One and Two represent a frame of reference from which the need for changes in economic conditions and government policies could be inferred and from which the probable effect of such changes could be analyzed. This analysis will be done in the next phase of the overall study, and the resulting report will be submitted to the Secretary of the Interior in the summer of 1972.

F O R E W O R D

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 to 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 (see p. *xxx*). 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.

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 (see p. *xxxi*). Thanks to the generous support of many cooperative organizations and people, this Committee is comprised of over 200 representatives of the oil, gas, coal, nuclear and other energy-related fields, as well as a number of financial experts. This broad makeup permitted an assessment to be made of the total energy outlook. In addition, the Committee felt it desirable to compare the fuel demand estimates made by its several task groups with the results of some comprehensive energy studies made by individual companies or other organizations. Battelle Northwest was retained to make a composite of such relevant studies.

The contents of the Interim Report (both Volumes One and Two) do not represent a probable forecast of the energy outlook, but rather only a frame of reference from which the need for changes in policies and conditions could be inferred and the probable effect of such changes analyzed.

The final report on this topic by the National Petroleum Council, which is scheduled for completion in July 1972, will (1) assess the potential impact on the U.S. energy outlook of various changes in economic conditions, technology and governmental policies for the balance of the century and (2) identify probable trends in energy demand/supply relationships between 1985 and the end of the century.

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*Membership shown in task group listings preceding individual chapters.

†Replaced Dr. Wilson M. Laird, June 17, 1971.

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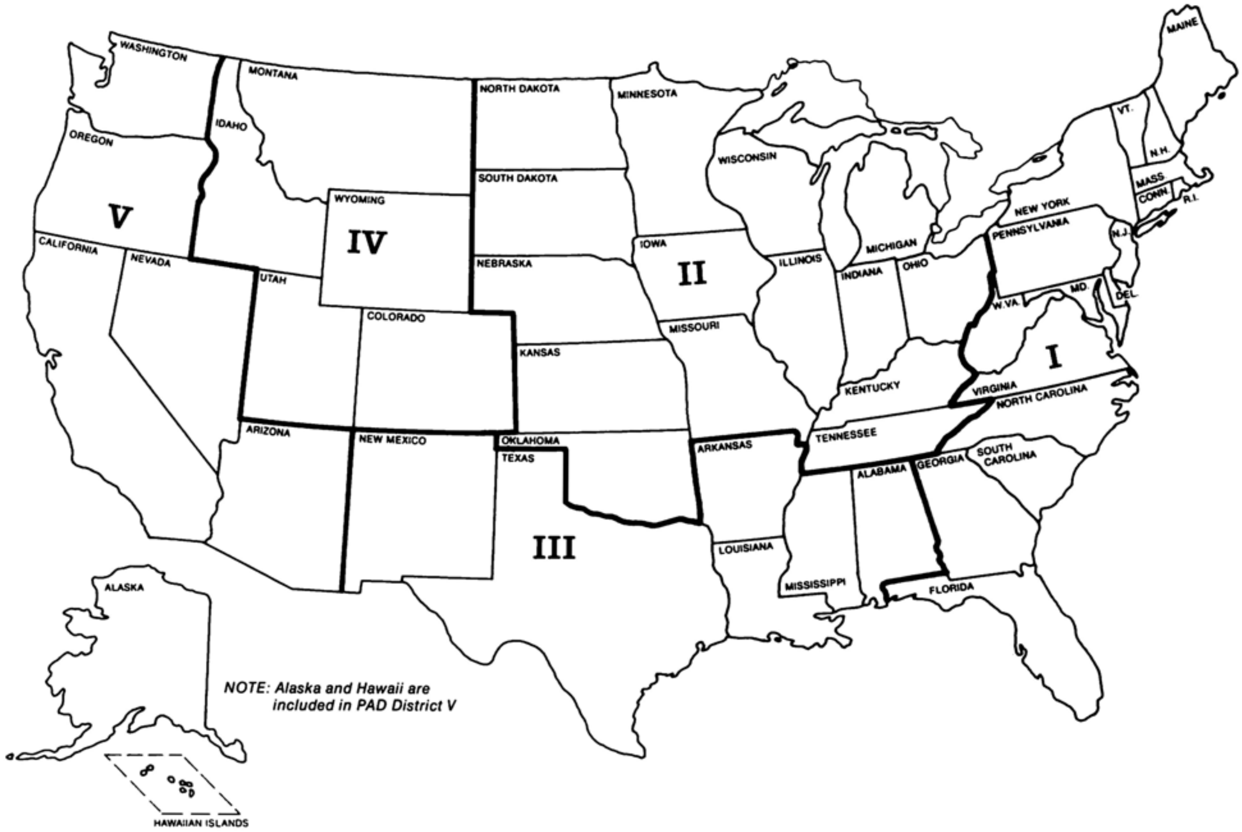

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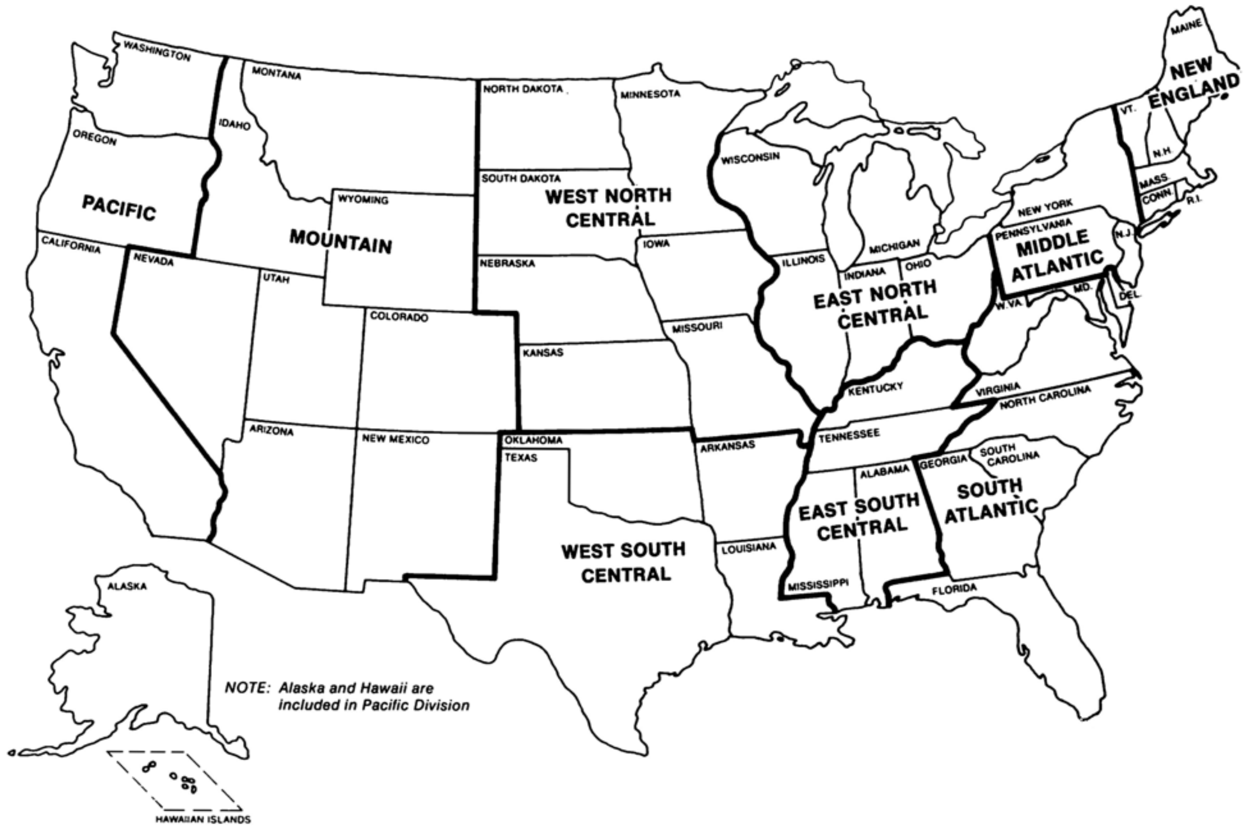

Extracts From Volume One

Extracted from
The National Petroleum Council's Interim Report
U.S. Energy Outlook: An Initial Appraisal 1971-1985
Volume One
July 1971

SUMMARY

This report summarizes the National Petroleum Council's "Initial Appraisal" of the U.S. energy outlook through 1985. Supply-demand relationships are projected assuming that current government policies and regulations[1] and the present economic climate for the energy industries would continue without major changes throughout the 1971-1985 period.[2]

ASSUMPTIONS OF INITIAL APPRAISAL

In line with maintenance of a basic "status quo", it was assumed that:

1. Recent physical levels of oil exploration and development drilling activity and exploration success trends would continue into the future.

2. The level of capital investment in gas exploration and development drilling activity would remain relatively constant and the past trends in the results of such activity would provide the basis for future expectations.

3. After domestic oil production capacity is reached, remaining requirements would be satisfied by imports. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign oil.

4. All presently feasible sources of gas supply, domestic and foreign, would be utilized. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign gas.

5. Nuclear power would be utilized to the maximum extent consistent with a feasible development program.

6. Coal production would rise to the degree necessitated by demand and technological advances would permit coal producers and consumers to meet environmental requirements.

These assumptions are generally optimistic. In view of past trends, the assumed levels of oil and gas exploratory activity, in particular, are not likely to be realized without substantial improvements in economic conditions and government policies. Similarly, the availability of foreign oil to meet shortfalls in domestic supplies cannot be assured. Significant limitations could arise for political or logistical reasons.

This initial appraisal, therefore, is not a forecast of what will probably happen in the future, and it should not be so interpreted. It is solely a set of projections, reflecting an optimistic view of what might happen without major changes in present government policies and economic parameters. These projections will be used as reference points by the Committee in its subsequent task of identifying and evaluating the changes in government policies and economic conditions which might contribute to an improved national energy posture.

---

[1] Particularly in respect to oil import controls, natural gas price regulation, leasing of federal lands, environmental controls, tax rates and research funding.

[2] This analysis relates to government policies prior to the President's June 4, 1971, Energy Message to Congress.

FINDINGS OF THE INITIAL APPRAISAL

In the initial appraisal, an assessment was made of total U.S. energy consumption by market sectors.[1] The Subcommittees for Oil, Gas and Other Energy Resources made independent assessments of the individual fuels involved. They applied their respective judgments in deciding what factors would affect demand for the particular fuel examined and took into account the probable supply of other fuels. From these projections, the Coordinating Subcommittee developed an energy supply-demand balance. The principal findings of the initial appraisal, made under the assumed conditions summarized above, were as follows:

1. *Energy Consumption*--U.S. energy consumption would grow at an average rate of 4.2 percent per year during the 1971-1985 period. The respective growth rates by market sectors would be as follows: electric utilities, 6.7 percent; nonenergy uses, 5.4 percent; transportation, 3.7 percent; residential and commercial, 2.5 percent; and industrial, 2.2 percent.

2. *Domestic Energy Supplies in Relation to Consumption*--In 1970 domestic energy supplies satisfied 88 percent of U.S. energy consumption. Under the assumptions of the initial appraisal, domestic supplies would grow at an average rate of 2.6 percent per year during the 1971-1985 period. Since domestic supplies would increase at a slower rate than domestic demand, the nation would become increasingly dependent on imported supplies. By 1985, domestic supplies would take care of about 70 percent of U.S. consumption.

3. *Petroleum Liquids*--Domestic supplies, consisting of crude oil, condensate and natural gas liquids, totaled 11.3 million barrels a day (B/D) in 1970, which was 31 percent of total energy consumption. Despite the addition of an estimated 2.0 million B/D from the Alaskan North Slope and another 2.7 million B/D from new discoveries to be made after 1970, total U.S. production in 1985 was estimated at only 11.1 million B/D. Therefore, in order to meet growing demands for petroleum liquids, imports would have to increase more than fourfold by 1985, reaching a rate of 14.8 million B/D in that year. Assuming the availability of foreign supply, oil imports would then account for 57 percent of total petroleum supplies and would represent 25 percent of total energy consumption. Most of the imports would have to originate in the Eastern Hemisphere because of the limited potential for increased imports from Western Hemisphere sources.

4. *Gas*--In the absence of supply limitations, potential gas demand would approximately double between 1970 and 1985, reaching a level of about 38.9 trillion cubic feet (TCF) per annum. Under current regulatory policies and federal leasing policies, however, the supplies of domestic natural gas (excluding North Slope) could be expected to fall from 21.82 TCF in 1970 to 13.00 TCF in 1985. By this time, another 1.50 TCF would be contributed by the Alaskan North Slope and 0.91 TCF from synthetic gas manufactured from coal and naphtha; meanwhile, imports from Canada could provide 1.15 TCF and imports of LNG and LPG could furnish an additional 4.93 TCF.[2] Taking all of these

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[1] For an assessment of requirements by geographic area as well, see Chapter One, Volume II.

[2] Supplies from all the sources mentioned could be made available only at prices substantially above those postulated for production of domestic natural gas under the assumptions of this initial appraisal.

sources into account, 1985 supplies would total only 21.49 TCF, or 1.25 TCF less than 1970 supplies of 22.74 TCF. Dependency on imports would rise from 4 percent of gas supplies in 1970 to more than 28 percent in 1985, assuming the availability of foreign supply. The shortfall in energy supply between potential gas demand and available gas supplies would have to be made up from increased supplies of other fuels.

5. *Coal*--Supply of domestic coal, including exports, would increase from 590 million tons in 1970 to 1,071 million tons in 1985. Coal reserves were judged ample and could support a faster growth rate in production. Potential constraints, however, were seen as being the availability of manpower and transportation facilities, health and safety regulations, and the need to develop a commercially proven technology for control of sulfur dioxide emissions.

6. *Nuclear*--Nuclear power supply would increase from 23 billion kilowatt hours (KWH) in 1970 to 2,067 billion KWH in 1985. This is consistent with estimates of the Atomic Energy Commission. Achievement of this level would depend primarily on resolving delays from siting, environmental and construction problems. No shortage of domestic fuels was foreseen, assuming prices for U_3O_8 up to $10 per pound. By 1985, nuclear energy would be supplying 48 percent of total electric power requirements.

7. *Other Fuels*--The remaining fuels--hydropower, geothermal power and synthetic crude from shale--would together contribute only 3 percent of energy requirements in 1985. Ceilings on the output of the first two would be imposed by physical limitations. Ceilings on the output of synthetic crude would be limited by government policy on leasing land, economics and technology; consequently only about 100,000 B/D would be obtainable from oil shale.

8. *Capital Requirements*--In order to achieve the initial appraisal energy balance, capital outlays for resource development, manufacturing facilities and primary distribution in the United States would have to total approximately $375 billion over the 1971-1985 period.[1] Not included in this estimate were other major sums for petroleum marketing, gas and electricity distribution, and the development of overseas natural resources needed to satisfy U.S. import requirements.

IMPLICATIONS OF THE INITIAL APPRAISAL

In the long run, all indigenous energy supplies that can be developed will be needed. Potential U.S. energy resources could physically support higher growth rates from domestic supplies than shown in this initial appraisal, particularly for coal, nuclear fuels, petroleum liquids and natural gas. U.S. coal reserves are ample to meet foreseeable needs. The quantity of original oil and gas in place, as estimated in the NPC report[2] on future U.S.

---

[1] Excludes capital outlays for Alaskan North Slope exploration, development and production. Includes capital outlays of $200 billion for electric power plants and transmission lines.

[2] As indicated in the NPC report *Future Petroleum Provinces of the United States* (July 1970), *if* discovered and produced, future production of crude oil would be 346 billion barrels (4.0 times past production) and future production of natural gas would be 1,195 trillion cubic feet (3.6 times past production). The discovery and commercial development of these potential resources will, however, take many decades and require major improvements in economic incentives.

petroleum provinces, exceeds the total of cumulative oil and gas production to date and the domestic demand for oil and gas projected in this appraisal. Also, the combined total of currently proven and potentially discoverable oil and gas as estimated in that report is above projected needs during the study period interval. It is extremely important to note, however, that these resources are not likely to be developed to their full potentials under the "status quo" assumption regarding government policies and economic conditions. For example, using the discovery rate projected in the initial appraisal, it would take almost a century to find the estimated discoverable oil projected in the referenced study.

Since the mid-1950's, the growth rate for domestic petroleum production has slackened, while that for imports of petroleum has increased. As a result, incentives and prospective profitability for exploration and development of hydrocarbon resources in the United States have decreased.[1] In the last few years, there has been a higher rate of growth in the market for domestic oil, but the "real" price of crude oil still remains below the level of the decade earlier.

Based on historical precedent, the assumption of U.S. oil and gas prices continuing at recent levels indicates that supplies of domestic oil and natural gas will decline in the future. However, an improved economic climate would encourage (1) increased exploration for new reserves of oil and gas and (2) increased recovery of oil from known reserves.

The extent to which indigenous supplies could be increased by these and other changes was not considered in this initial appraisal, but will be assessed in the final report scheduled for completion in July 1972.

At this time, it is appropriate only to note certain areas of concern that are implicit in the continuation of existing conditions. These items can be conveniently placed in four groups:

1. *Government Policies*--Continuation of present government policies, particularly in respect to leasing of federal lands, environmental controls, health and safety, tax rates, research funding, natural gas price regulation, and import policies, clearly will result in a sharp rise in national dependence on imported energy sources, particularly petroleum liquids. This will require careful assessment, in respect to both national security aspects and the impact on the U.S. balance of payments. Furthermore, the United States cannot expect indefinitely to be able to increase imports of foreign oil. Towards the end of the century, foreign oil supplies may prove insufficient to meet all potential demands.

   Continuation of present government policies will also result in available gas supplies being equal to only about one-half of market requirements in 1985. In view of the indicated availability of substantial undiscovered domestic reserves, a critical review of natural gas regulations and other parameters impinging on the incentives for expanded exploratory efforts is clearly in order and urgently needed.

2. *Physical Facilities*--The satisfaction of the nearly doubled energy requirements of 1985 will require enormous additions of new facilities, which will not easily be forthcoming under existing political, social and economic conditions. *In petroleum*, the importation of an incremental 10-11 million B/D of overseas crude oil and products above the 1970 level would require more than 350 tankers, each of 250,000 deadweight tonnage (DWT). No U.S. ports are presently equipped to receive

[1] For further discussion of effect of economic factors in 20 years after World War II, see the report of the National Petroleum Council, *Factors Affecting U.S. Exploration, Development and Production*, dated January 31, 1967.

such tankers, so new terminals would have to be developed in coastal areas. Similarly, the increase in refined products requirements would necessitate net additions of about 10 million B/D to domestic refining capacity over the 15-year period. This would involve construction at about 2.5 times the rate of the past decade. *In gas*, the importation of 4 TCF of LNG annually by 1985 would require the building of 120 tankers each having a maximum capacity equivalent of approximately 790,000 barrels. In addition, such operations would require the building of liquefaction plants at the loading terminals and the building of unloading terminals, regasification plants and storage and transportation facilities at points of delivery. *In coal*, the doubling of mine output would involve the development of Western coal reserves with associated transportation to markets as well as expanded development of underground mines in the East and Midwest. *In nuclear power*, the pace of construction of new plants would have to rise very sharply from recent levels, reaching a capability of bringing thirty 1,000-megawatt plants on line each year from 1980 through 1985.

3. *Financial Requirements*--Annual new investment required to finance development of natural resources and construction of new facilities would greatly exceed the levels of recent years. Funds provided from operations of energy industries at present price levels would fall far short of meeting these capital requirements. Environmental regulations affecting the supply, transportation and consumption of all fuels would further increase investment costs. All these things indicate increasing energy costs.

4. *Technology*--The doubling of energy consumption over the next 15 years implies a sharp step-up in all kinds of measures needed to protect the environment, both at the points of energy production and use. The urgent need for energy also provides varied research challenges, including problems such as new coal mining methods, new exploratory techniques, new methods of increasing the recovery of oil and gas, new energy transportation methods, advanced nuclear technology, and the development of commercial processes for flue-gas desulfurization and for manufacture of synthetic liquid and gaseous fuels from oil shale and coal.

Finally, it should be noted that long lead times are involved in the orderly development of energy resources. Therefore, it is essential that the many considerations bearing on the selection of an optimum national energy posture be brought into sharp focus at the earliest possible date. In its final report on the U.S. energy outlook, the National Petroleum Council will seek to provide as much pertinent material as possible, including analyses of alternatives open to both government and industry.

ADDITIONAL STUDIES

The NPC Committee on U.S. Energy Outlook has already started to develop additional analyses of changes in industry and/or government programs and policies and changes in economic conditions which would lead to the following effects:

1. Increase indigenous energy supplies

2. Enhance the environment

3. Maintain the security of the nation's energy supplies

4. Increase efficiency in the production and use of fuels, particularly through technological research and development

In the process of this additional work, special attention will be given to costs, including the range of cost increases involved in various steps to improve the energy supply situation, and the resultant impact of such increases on demand. The Committee recognizes that price levels will have a significant impact on both the supply of and demand for various energy resources; an effort will be made to evaluate the elasticity of demand and supply for each major type of energy.

ENERGY OUTLOOK UNDER INITIAL APPRAISAL ASSUMPTIONS

(Originally Chapter One of Volume One)

Projecting the energy outlook in this initial appraisal required estimates of total energy consumption and total energy supply, and these estimates had to be balanced. In order that consumption by many different market sectors and supply by many different energy sources could be aggregated, a common denominator was required. For this purpose, estimates were expressed in terms of British Thermal Units (BTU's). (For a fuller definition, see box insert on p. *xxiv*.)

Besides these estimates in BTU's and other physical units of measure, a projection of the energy outlook involved certain gross assessment of at least the most predictable capital requirements for reaching the needed energy supply. Like energy consumption and supply, investment will be covered in this chapter only briefly. More details will appear in the separate chapters on individual fuels.

U.S. ENERGY CONSUMPTION

Total U.S. energy consumption will probably grow at an average annual rate of 4.2 percent during the 15 years 1971-1985, thus almost doubling its starting 1970 volume by the end of the period. Measured in trillions of BTU's, energy consumption should increase as follows:

Year	Volume	Percent Increase Over 1970
1970	67,827	--
1975	83,481	23.1
1980	102,581	51.2
1985	124,942	84.2

Source: Energy Demand Task Group

This outlook is predicated on important assumptions regarding environmental restraints, basic economic trends, prices, fuel availability, capital requirements and technological developments which will be reexamined in subsequent variant analyses.[1]

As developed more fully in the demand projections in Chapter Two, the overall average yearly growth rate conceals a wide range of variation in the growth rates of the five major market sectors that account for total energy consumption. These are (1) residential and commercial, (2) industrial, (3) transportation, (4) electrical utilities,[2] and (5) nonenergy uses for fuel.

---

[1] For further discussion see Chapter One.

[2] Though commonly thought of as energy *suppliers*, electric utilities are actually also energy *users*, consuming coal, gas, oil, nuclear fission products, etc. Thus utilities *convert* one form of energy to another. In technical parlance, electrical utilities are users of *primary* energy sources, and suppliers of *secondary* energy. In every stage of their operation--production, transmission and distribution--some BTU's are lost.

Throughout the body of this text, utilities are treated as energy consumers. Thus, to avoid duplication, the consumption of electricity by other consuming sectors (such as industrial and residential) has been omitted from statistics in their total energy consumption.

For a picture of energy consumption patterns by consuming sector with electricity consumption included in the figures for the other sectors, the reader is referred to Chapter One.

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 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.

ENERGY SUPPLIES

To satisfy demand of the magnitude expected will not be easy under the initial appraisal assumptions as to economic climate and government policies. The pattern of fuel sources used will shift markedly in response to such factors as supply limitations, interfuel competition and U.S. import policies. Oil and coal will continue to supply roughly 43 percent and 19 percent, respectively, of energy consumption; however, imports are projected to grow from 22 to 57 percent of oil supply.

Potential gas demand, without consideration of supply limitations or changes in the energy pricing structure, would almost double, reaching 38.9 TCF by 1985. During the same period, however, the available supply of gas (including imports of LNG and LPG, plus synthetic pipeline gas) would decline from 22.7 TCF in 1970 to 21.5 TCF in 1985. It is thus obvious that consumption of gas is inhibited by a lack of foreseeable supply, assuming the continuation of current regulatory policies and economic conditions. It is equally apparent that any shortfall in total energy supplies resulting from a lack of gas must be made up from increased supplies of other fuels. The total gas supply projected for the years through 1985 holds almost even over the period, but dependence on imports rises from 4 percent in 1970 to over 28 percent of total gas supply in 1985. Moreover, gas is projected to decline from 33 to 18 percent of total energy consumption.

Nuclear energy is projected to grow from less than 1 percent to more than 17 percent of total energy. Remaining energy needs will be met from geothermal and hydropower sources.

To develop these projections, the Oil, Gas and Other Energy Resources Subcommittees made independent assessments of the individual fuels (see Chapters Three through Nine). Each group made its own judgment of the factors that would affect demand for the particular fuel examined, including the supply of other fuels. The independent assessments of supply and demand of the several fuels made by the respective Task Groups did not total exactly to the overall energy forecast developed by the Energy Demand Task Group (see Exhibit 3 for the Energy Trial Balance). The Coordinating Subcommittee accordingly adjusted the separate Task Force projections of supplies to conform with the total energy requirements as forecast by the Energy Demand Task

Group. The necessary adjustments were small, ranging from 1.4 percent of total demand in 1975 to 2.4 percent in 1980 and 2.1 percent in 1985.

To achieve the needed gains in supplies, slight increases were assumed to be available from the two sources that could most probably be increased, namely, oil imports and domestic coal. In the absence of any clear-cut indication as to which of these two sources should be counted on for what, the Committee made a purely arbitrary allocation, getting one-third of the requirements from oil imports and two-thirds from domestic coal, as follows:

TABLE I

RECONCILIATION OF TASK FORCE PREDICTIONS, FUEL DEMAND AND SUPPLY

Fuel Demand and Supply Requirements	1975	1980	1985
Projected by the Energy Demand Task Group (Trillion BTU's)	83,481	102,581	124,942
Projected by the Separate Fuel Task Groups (Trillion BTU's)	82,347	100,116	122,299
Difference (Trillion BTU's)	1,134	2,465	2,643
Residual Fuel Oil Equivalent of Difference (Thousand B/D)	490	1,070	1,150
Coal Equivalent of Difference (Million Tons)	45	100	105
Fuel Oil Share (at One-Third of the Difference, Thousand B/D)	165	360	400
Coal Share (at Two-Thirds of the Difference, Million Tons)	30	65	70
Residual Fuel Share as a Percent of Total Residual Fuel Demand	5%	9%	9%
Coal Share as a Percent of Total Domestic Coal Demand	4%	8%	8%

Source: Coordinating Subcommittee.

In subsequent tabulations, it will be routinely noted whether supply figures are adjusted (to conform with Energy Demand Task Group Estimates) or unadjusted (Individual Fuel Task Group figures).

From the above projections, the Coordinating Subcommittee developed the supply-demand balance which is shown in Table II. The supply data are repeated in Table III in the physical units appropriate for the respective fuels and depicted graphically in Figure 1.

CAPITAL REQUIREMENTS

The capital requirements to meet U.S. energy needs through 1985 are extremely large. Taken to the wholesale operations level (i.e., exclusive of petroleum marketing, gas distribution, electricity distribution, etc.), these capital requirements (in constant 1970 dollars) for the 15-year period 1971-1985 are estimated as follows:

	Billion Dollars
Oil and Gas Production*	$ 92
Oil Refining*	20
Oil Transportation (Marine and Domestic Pipelines)	18
Gas Transportation	21
Coal Production	9
Coal Transporation	6
Nuclear Production and Processing	5
Oil from Shale	0.5
Syngas Plants	2.5
Subtotal	$174
Electric Power Plants and Transmission Lines	200
TOTAL	$374

* Excludes foreign facilities.

This sum represents about 14 percent of the projected nonresidential fixed investment of the United States for the period 1971-1985.

TABLE II

ENERGY BALANCE--INITIAL APPRAISAL
(In Trillions of BTU's)

	1970	1975	1980	1985
U.S. Domestic Energy Consumption*	67,827	83,481	102,581	124,942
Projected Domestic Supply:†				
Oil - Conventional‡	21,048§	22,789	24,323	23,405
Synthetic	--	--	--	197
Subtotal	21,048	22,789	24,323	23,602
Gas - Conventional‡	22,388§	20,430	18,030	14,960
Synthetic	--	380	570	940
Subtotal	22,388	20,810	18,600	15,900
Coal‖	13,062	16,310	19,928	23,150
Hydropower	2,677	2,840	3,033	3,118
Nuclear	240	3,340	9,490	21,500
Geothermal	7	120	343	514
TOTAL DOMESTIC SUPPLY	59,422	66,209	75,717	87,784
(Percent of U.S. Consumption)	87.6	79.3	73.8	70.3
Imports Required to Balance:				
Oil	7,455	15,662	22,984	30,878
(Percent of Oil Supply)	22.0	40.7	48.6	56.6
Gas	950	1,610	3,880	6,280
(Percent of Gas Supply)	4.1	7.2	17.3	28.3
TOTAL IMPORTS	8,405	17,272	26,864	37,158
(Percent of Energy Supply)	12.4	20.7	26.2	29.7

* As projected by the Energy Demand Task Group.
† As projected by the various Fuel Task Groups; oil and coal adjusted to meet demands as predicted by the Energy Demand Task Group (see Table I).
‡ Includes Alaska North Slope starting in 1975 for oil and 1977 for gas.
§ Excludes additions to oil (2,086) and gas (132) stocks.
‖ Excludes BTU's consumed in conversion of coal to syngas.

Source: Coordinating Subcommittee and indicated Task Groups.

TABLE III

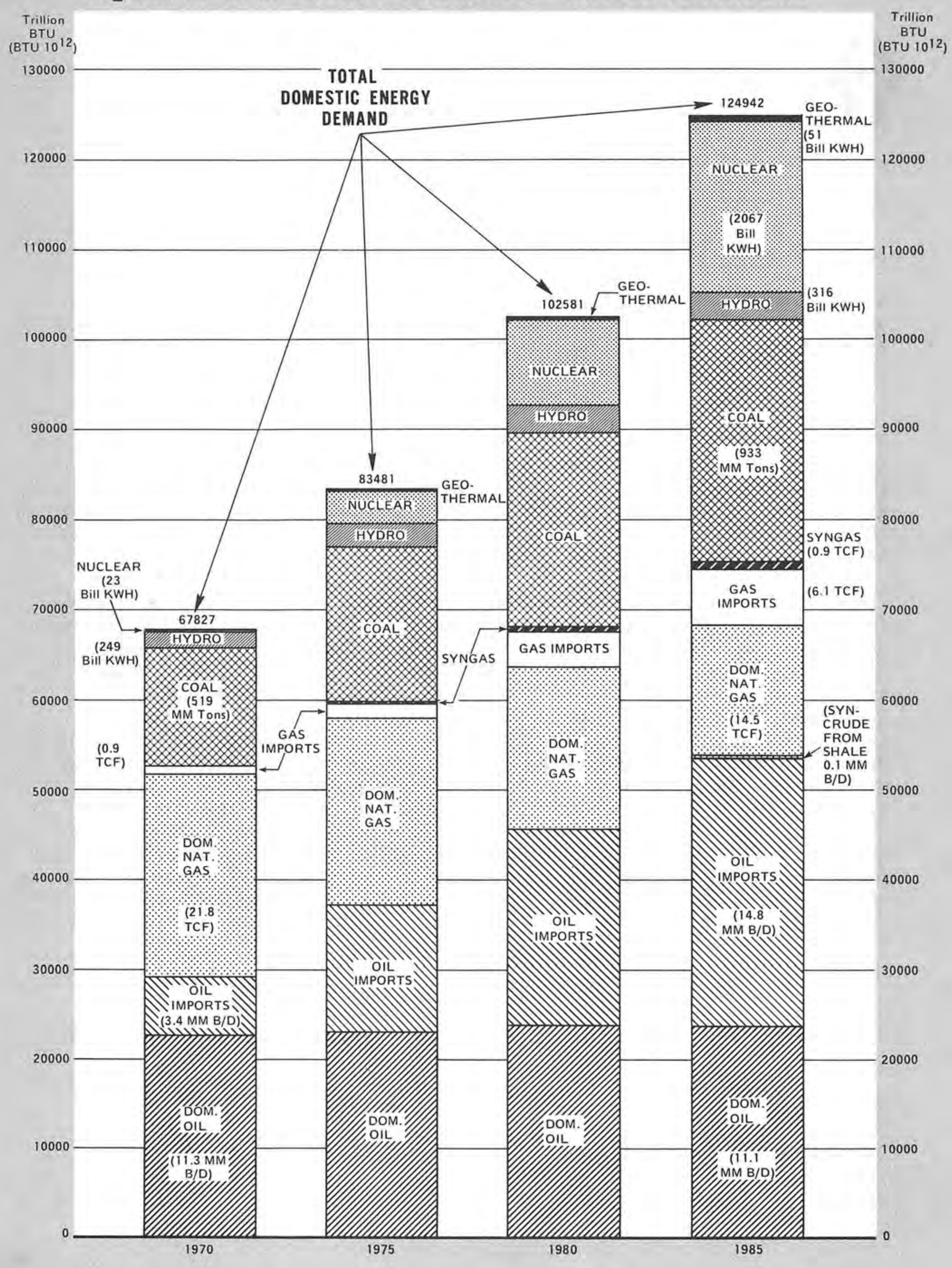
ENERGY SUPPLY--INITIAL APPRAISAL
(In Conventional Physical Units)

	1970	1975	1980	1985
Projected Domestic Energy Supply				
Oil - In Million B/D				
Conventional	11.3	11.1	11.8	11.1
Synthetic	-	-	-	0.1
TOTAL	11.3	11.1	11.8	11.2
Gas - In Trillion CF				
Conventional	21.82	19.80	17.47	14.50
Synthetic	-	0.37	0.55	0.91
TOTAL	21.82	20.17	18.02	15.41
Coal - In Millions of Short Tons				
For Domestic Use*	519	651	799	933
For Export	71	92	111	138
TOTAL	590	743	910	1,071
Other - In Billions of KWH				
Hydro	249	271	296	316
Nuclear	23	326	926	2,067
Geothermal	0.7	12	34	51
TOTAL	272.7	609	1,256	2,434
Imports Required to Balance:				
Oil - In Million B/D†	3.4	7.3	10.7	14.8
Gas - In Trillion CF	0.92	1.55	3.75	6.08

	1970	1975	1980	1985
* Includes adjustment of million tons	-	30.0	65.0	70.0
† Includes adjustment of million B/D	-	0.2	0.4	0.4

Source: See Table II.

Figure 1. U.S. ENERGY BALANCE – INITIAL APPRAISAL



Source: See Tables II and III.

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

C O P Y

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,

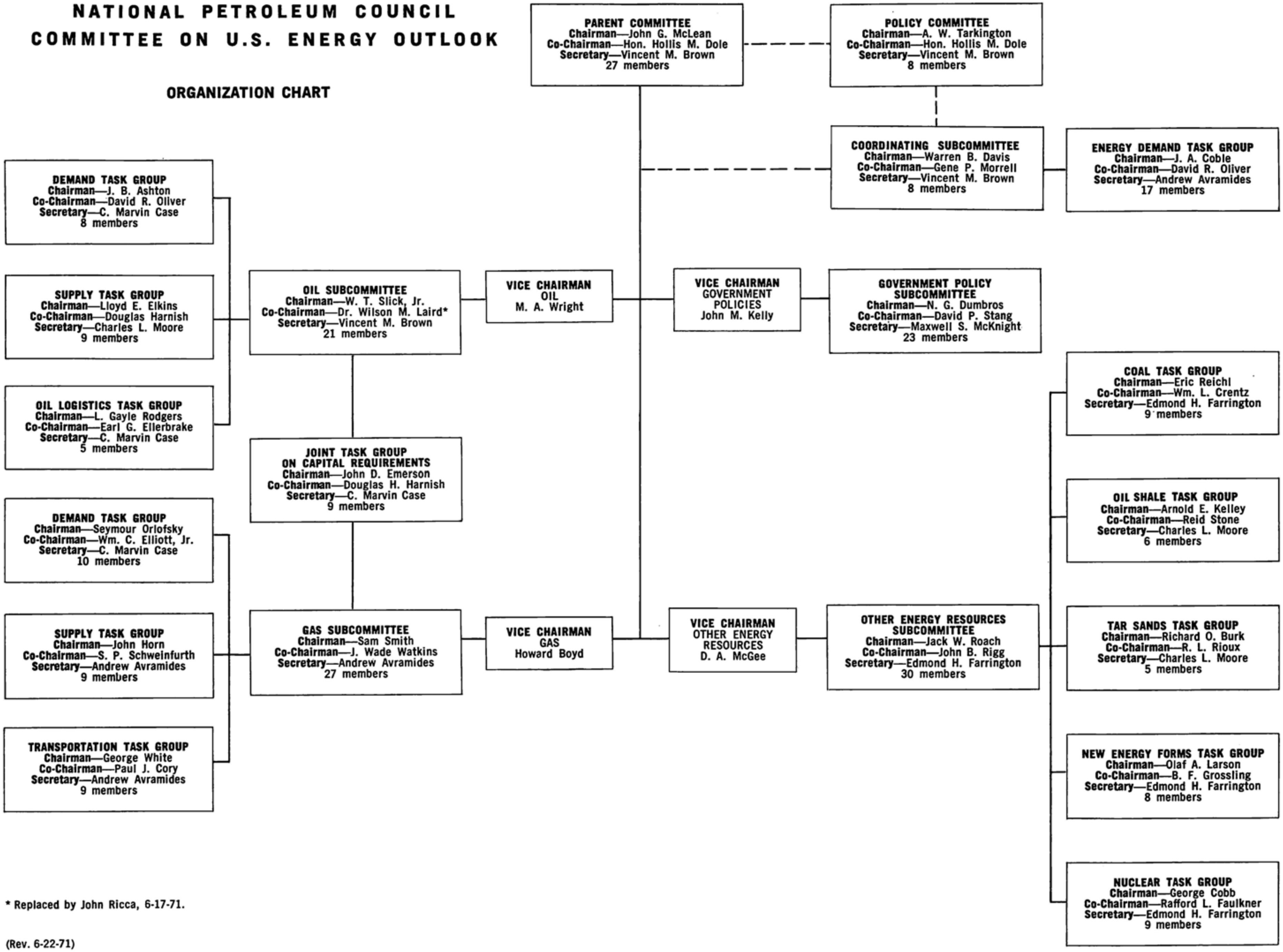
/s/ HOLLIS M. DOLE

Assistant Secretary of the Interior

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

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



* Replaced by John Ricca, 6-17-71.

(Rev. 6-22-71)

(Originally Exhibit 3)

DEVELOPMENT OF INITIAL APPRAISAL ENERGY BALANCE

In addition to the assessment of total energy requirements by the Energy Demand Task Group, the Oil, Gas and Other Energy Resources Subcommittees made independent assessments of the individual fuels involved (see Chapters Three through Nine). Each group made its own judgment of the factors which would affect demand for the particular fuel examined, including the supply of other fuels. The projections as to the *strictly domestic* supplies available in the period 1971-1985, given the assumptions for the initial appraisal, are shown in Table XVII.

TABLE XVII

PROJECTED U.S. DOMESTIC ENERGY SUPPLY--INITIAL APPRAISAL*
Unit: Trillion BTU's (BTU 10^{12})

	1970	% of Demand†	1975	% of Demand†	1980	% of Demand†	1985	% of Demand†
Oil Subcommittee	21,048‡	31.1	22,789	27.3	24,323	23.7	23,405	18.7
Gas Subcommittee	22,388‡	33.0	20,430	24.5	18,030	17.6	14,960	12.0
Other Energy Resources Subcommittee:								
Coal§	13,062	19.3	15,554	18.6	18,284	17.8	21,388	17.1
Hydropower	2,677	3.9	2,840	3.4	3,033	3.0	3,118	2.5
Nuclear	240	0.3	3,340	4.0	9,490	9.3	21,500	17.2
Geothermal	7	--	120	0.1	343	0.3	514	0.4
Synthetic Oil	--	--	--	--	--	--	197	0.2
Synthetic Gas	--	--	380	0.5	570	0.5	940	0.7
TOTAL DOMESTIC SUPPLY	59,422	87.6	65,453	78.4	74,073	72.2	86,022	68.8

* As projected by individual fuel subcommittees.

† As a percentage of total energy requirements

‡ Excluding additions to oil (2,086) and gas (132) stocks.

§ Does not include BTU's consumed in conversion of coal to syngas.

A further comparison of the projected consumption of energy in the United States through 1985 with the added projections of imported supply of energy (under continuation of current conditions without major change) is presented in Table XVIII.

TABLE XVIII

ENERGY TRIAL BALANCE--INITIAL APPRAISAL
Unit: Trillion BTU's (BTU 10^{12})

	1970	1975	1980	1985
A. Total Domestic Energy Consumption	67,827	83,481	102,581	124,942
B. Total Projected Domestic Supply	59,422	65,453	74,073	86,022
C. Demand in Excess of Domestic Supply	8,405	18,028	28,508	38,920
D. Indicated Import Levels Derived by Task Groups Under Initial Appraisal Assumptions				
Oil	7,455	15,284	22,163	29,997
Gas	950	1,610	3,880	6,280
Total Imports	8,425	16,894	26,043	36,277
E. Indicated Remaining Difference of Demand Exceeding Supply	--	1,134	2,465	2,643
F. Remaining Difference as Percent of Energy Demand	--	1.4%	2.4%	2.1%

The "indicated differences" between the total energy consumption projected by the Energy Demand Task Group and the sum of the several fuel task groups' individual supply projections range from 1.4 percent to 2.4 percent of domestic energy consumption. These differences represent energy requirements that must be met by coal or oil, the only two fuels found to have any significant flexibility in total supply. Considering the many parameters of fuel demand and utilization would lead to the conclusion that this demand shifting will probably take place within the Utility and the Industrial market sectors. Most of the oil requirement would probably be met in the form of residual fuel.

The indicated differences and their fuel equivalents are:

	1975	1980	1985
DIFFERENCE--Trillion BTU's	1,134	2,465	2,643
COAL EQUIVALENT--Million Tons	45	100	105
RESIDUAL FUEL OIL EQUIVALENT--Thousand B/D	490	1,070	1,150

In the absence of any clear-cut indications of a more accurate distribution, the Committee arbitrarily allocated these requirements one-third to oil and two-thirds to coal. The resulting volumes and their relationship to base requirements are:

	1975	1980	1985
OIL---Thousand B/D	165	360	400
---Percent of Residual Fuel Demand	5%	9%	9%
COAL--Million Tons	30	65	70
--Percent of Total Domestic Coal Demand	4%	8%	8%

Given the projected U.S. energy demand shown above, and having applied the adjustments to energy supply as discussed in the immediate preceding section, the Committee developed the Initial Appraisal Energy Supply-Demand Balance shown as Table II in the body of the report.

Summaries of Task Group Reports

Chapter One

Energy Consumption Task Group

Energy Demand

ENERGY DEMAND TASK GROUP

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ENERGY DEMAND TASK GROUP REPORT

ABSTRACT

OUTLOOK

The estimated growth rate for total U.S. energy consumption during the period 1970-1985 is 4.2 percent per year. At this rate, demand will about double over the next 15 years. Although all major markets for energy will participate in this expansion, the electric utility market will outpace all others, greatly increasing its relative share, as shown in Table I.

TABLE I

PERCENTAGE SHARES OF U.S. ENERGY CONSUMPTION

Sector	Primary Energy* 1970	Primary Energy* 1985	Total Energy† 1970	Total Energy† 1985
Residential/Commercial	19.2	15.0	23.2	21.3
Industrial	26.2	19.7	29.6	24.7
Transportation	24.0	22.6	24.1	22.7
Electric Utilities	24.6	35.5	*	*
Electricity Conversion	*	*	17.1	24.1
Non-Energy & Miscellaneous	6.0	7.2	6.0	7.2
TOTAL	100.0%	100.0%	100.0%	100.0%

* *Primary energy consumption* reflects the combined inputs of all fossil fuels for all consuming sectors except electric utilities which additionally incorporates inputs of nuclear and waterpower.

† *Total energy consumption* differs from primary in that the electricity output is assigned to the residential/commercial, industrial and transportation sectors. The remaining portion of the electric utility demand, i.e., conversion, transmission and distribution losses, is shown under the "electricity conversion" category.

In addition to a detailed analysis of market share by consuming sector, this chapter examines the growth rate in demand by geographic area. An area analysis of total energy demand indicates that growth is likely to be more rapid in the southern and western parts of the United States.

BACKGROUND AND ASSUMPTIONS

The strong energy growth rates experienced during the past decade (4.3 percent) and projected for the future reflect several significant developments in the economy such as:

- Sustained economic growth with real Gross National Product (GNP) projected at an average annual rate of approximately 4.2 percent
- Population and number of households expected to increase by 1.1 percent and 1.7 percent per year respectively

- A growing use of energy for environmental improvement.

In addition to economic and demographic assumptions, the energy projections were based on several other important premises of a more speculative nature:

- Although there may be limitations on supplies of individual energy resources, the necessary technology to permit fuel substitution would be developed. (For example, it was assumed that an economic process for removing sulfur from stack gases would be developed by the mid-1970's.)

- *Moderately* higher energy prices would probably not significantly affect the demand for total energy.

- The government would not adopt policies which would significantly restrict the rate of increase in energy use.

- The various energy industries will attain levels of profitability adequate to attract the large amounts of capital needed to approximately double the size of industry operations in the next 15 years.

SUMMARY OF ENERGY DEMAND TASK GROUP REPORT

SCOPE

This chapter of the National Petroleum Council study deals with "total energy" rather than with the consumption of individual fuels and waterpower. The non-energy use of fuels also is projected to 1985 so that the total demand for fuels plus all other forms of energy can be related to estimates of total supplies that will be available for U.S. consumption.

As in other parts of this study, the energy analysis is concerned mainly with long-term trends, as contrasted to short-term changes such as those caused by business cycles, abnormal weather or temporary supply difficulties. The years selected as "benchmarks" (for quantitative evaluation) were 1970, 1975, 1980 and 1985. Although the "base year" 1970 has been characterized by many unusual economic and political circumstances, it appears that the impacts of such abnormalities will not greatly affect the long-term growth rates shown in Table II, p. 7. The rather steady growth rates for total energy tend to conceal many of the problems that will beset the various fuel industries. Such problems, however, will be analyzed in the chapters on fuel supply and demand.

In recognition of the fact that energy problems and policies are not uniform throughout the country, total energy demand has been projected for each of the five Petroleum Administration for Defense (PAD) Districts covering the same benchmark years.

The PAD District I (East Coast) projection is divided into three Census Divisions--New England, Middle Atlantic and South Atlantic. The East North Central Census Division (a part of PAD District II) also is shown separately. All such geographical breakdowns have been developed for each of the major markets.

METHODOLOGY

As an initial step in its study, the Energy Demand Task Group examined earlier energy forecasts by others. Based on this examination, it appeared that a fundamental change had taken place over the past decade in the outlook for energy. Analysis of a recent comparison of energy forecasts prepared for the President's Office of Science and Technology showed that, as a rule, the later the date of the forecast, the higher the level of projected energy demand.* The highest forecast of energy consumption for 1970, which was published in 1968, subsequently proved to be 6.5 percent below the actual volume for that year; furthermore, all of the published long-term projections seem to be much too conservative. For this reason, among others, the task group decided that it was essential to obtain projections of total energy demand that would be more current. These were obtained from the energy studies of seven companies (six petroleum companies and the Chase Manhattan Bank), all of which have had long experience in energy forecasting.

The projections of total energy have been derived by analysis and synthesis of the component markets, rather than by assuming a fixed relationship between energy demand and GNP, or some other economic index. While the energy/GNP relationship frequently is useful, past experience in the United States indicates that the ratio has changed from time to time (as shown in Figure 1 on the following page) and that it is not likely, by itself, to provide a firm basis for forecasting. However, assumptions as to the outlook for GNP and many other economic and technological factors have been used as a framework for developing the component market projections.

In this report, electric power is treated in two different ways: In the "primary energy" analysis there is an electric utility sector which shows the combined power plant *inputs* of all fossil fuels, plus nuclear power and waterpower, while other consuming sectors include fossil fuels only. In the second method, the classification is changed so that the amounts of electricity consumed by each sector are incorporated in residential/commercial, industrial and transportation demands. In this case the electric utility sector drops out.

The major components of primary energy demand are the following five markets:

- *Residential/commercial* markets for fossil fuels accounted for about 19 percent of 1970 total energy consumption in the United States. About two-thirds of this total were used for *residential* heating, cooling, cooking and water heating. The remainder was consumed for similar purposes in apartment houses, stores, hospitals, schools, hotels, restaurants and other commercial and public establishments.

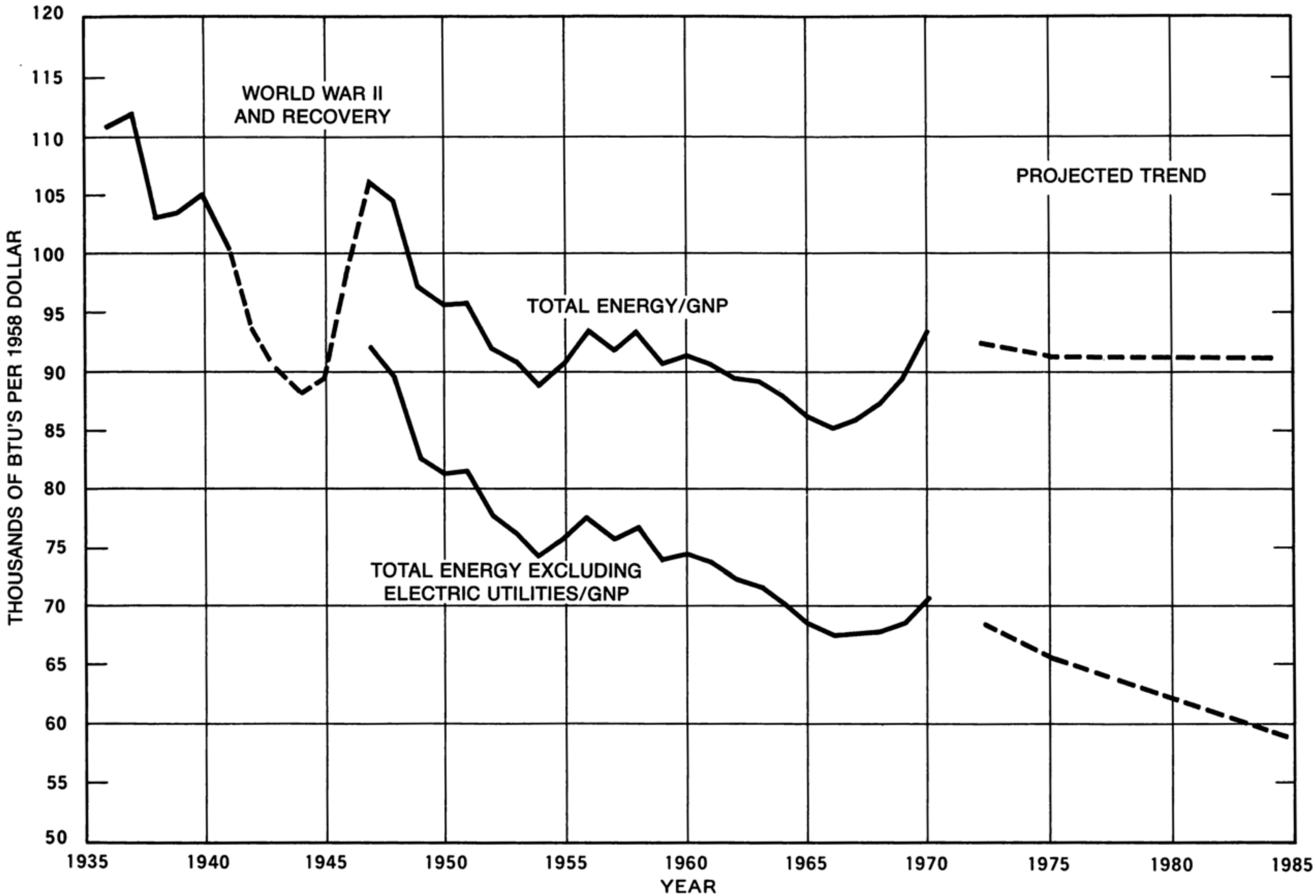
- The *industrial* market for fossil fuels comprised 26 percent of total energy demand. Such fuels are used primarily for manufacturing and mining operations.

- *Transportation* consumption (which represented 24 percent of total energy demand) includes major markets such as automotive, aviation, railroad, and ships' bunkers, plus other minor uses.

- *Electric utilities* consumed almost 25 percent of the Nation's 1970 "primary energy," meaning fossil fuels and fossil-fuel equivalents of nuclear, geothermal and waterpower. Such utility fuel consumption is termed *input*; the *output* of electricity is regarded as a "secondary" form of energy which is sold mainly to the residential/commercial and industrial markets where it competes with fossil fuels. The differences between *input* and *output* represent the energy conversion losses due to electric power generation. In addition, there are losses in electricity transmission and distribution which amount to about 8.5 percent of the output.

- *Non-energy and miscellaneous* uses accounted for 6 percent of the total primary energy materials and, therefore, must be added to energy demand in order to balance supply with demand. Non-energy uses include

*Battelle Northwest, *A Review and A Comparison of Selected United States Energy Forecasts* (December 1969).



Source: Energy Demand Task Group

Figure 1. Ratio of U.S. Energy Consumption to Real GNP.

lubricants, asphalts, petrochemicals and other raw materials. Miscellaneous includes both energy and non-energy "unaccounted for" items.

FINDINGS

1. *Total Energy*

The findings of this study indicate that energy consumption probably will grow at an average rate of 4.2 percent per year over the next 15 years, compared to 4.3 percent for the 1960-1970 period. This outlook, however, is predicated on important assumptions regarding environmental restraints, basic economic trends, prices, fuel availability, capital requirements and technological developments which will be reexamined in subsequent analyses. Although the contributors to this study differed substantially with respect to outlooks for several of the causal factors, the variation in estimates of *total energy demand* was relatively small: All of the long-term energy growth forecasts by individual participants showed rates of 4.1 percent or 4.2 percent per year, except for one at 4.3 percent and one at 3.8 percent.

The projection of real GNP was one of the items on which there was a considerable difference of opinion within the task group. Although the range of projections of real GNP was somewhat greater than that for energy growth, the task group consensus of a 4.3-percent gain annually through 1975 is generally consistent with the forecast of the Council of Economic Advisers. It is expected that this rate will gradually decline thereafter to 4 percent during the 1980-1985 period. Overall total energy consumption is projected to grow at about the same rate as real GNP.

There are two major reasons for expecting a leveling in the long-term declining trend of the energy/real GNP ratio: As illustrated by Figure 2 (p. 6), electricity will provide a growing proportion of the final consumption, which will tend to increase the use of primary energy for conversion purposes. Second, more severe environmental controls will require a considerable increase in the use of energy. (It has been assumed that the technology necessary for meeting environmental standards will be developed.)

Population and other demographic trends were used to forecast energy demand in some individual sectors. In the judgment of the task group, U.S. population growth during the forecast period will increase at a relatively slow rate, such as that projected by the Bureau of the Census' Series D. The population growth rate of Series D is only about 1.1 percent annually; however, the labor force and household formations will be expanding at the higher rate of 1.7 percent, reflecting the high birth rates of the late 1940's and the 1950's.

2. *Energy Consumption by Major Markets*

The following discussion of individual energy markets will be based on the projections in both Table II (p. 7), which deals with primary energy, and Table III (p. 8), which incorporates electricity into the consuming sectors where it is used. As an item of special interest, the fuel equivalents that are used up in the process of generation and transmission of electric power have been summarized in Table I under the category, "electricity conversion," although they might just as well be classified under "industrial" along with some of the other types of energy conversion losses.

Tables II and III bring out a number of salient trends in energy consumption over the 15-year period 1970-1985. These trends include (1) a rising *absolute volume* of demand for all major markets as measured in BTU's; (2) *declining consumption shares* for all but two major users as shown in the percentage breakdown figures; (3) a rising share of BTU's lost in the process of converting other fuels into delivered electricity; and (4) strong growth rates, generally tapering off a bit toward the end of the period.

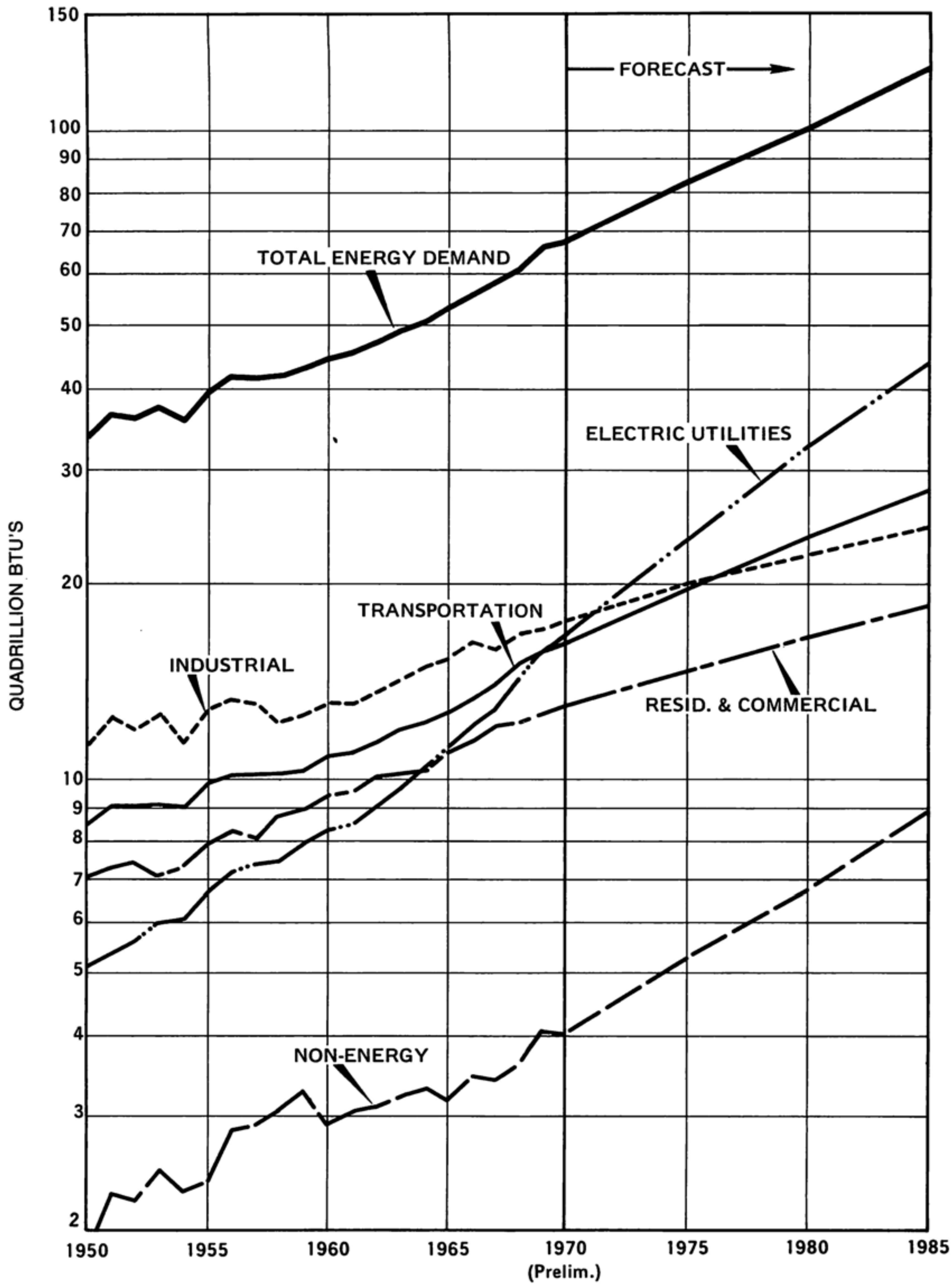


Figure 2. Total U.S. Primary Energy Consumption by Consuming Sectors.

a. Residential/Commercial

Many of the factors that have caused this sector to grow at a rate of 4 percent per year over the past decade (as shown in Table III) will be operating in the future. Large increases are expected in new households, labor force and family income plus a continuing shift of population to the suburbs or to

TABLE II

U.S. PRIMARY ENERGY CONSUMPTION PROJECTION
BY CONSUMING SECTORS

U.S. Primary Energy* Consumption in Trillions of BTU's

Sector	1960	1970	1975	1980	1985
Residential/Commercial	9,426	12,994	14,733	16,669	18,768
Industrial	13,056	17,798	20,039	22,341	24,667
Transportation	10,817	16,282	19,905	23,870	28,214
Electric Utilities	8,387	16,695	23,525	32,996	44,363
Non-Energy & Miscellaneous	2,916	4,058	5,279	6,705	8,930
TOTAL	44,602	67,827	83,481	102,581	124,942

Average Annual Percent Change in U.S. Primary Energy† Consumption

Sector	1960-70	1970-75	1975-80	1980-85	1970-85 Projection
Residential/Commercial	3.3	2.6	2.5	2.4	2.5
Industrial	3.1	2.4	2.2	2.0	2.2
Transportation	4.2	4.1	3.7	3.4	3.7
Electric Utilities	7.2	7.1	7.0	6.1	6.7
Non-Energy & Miscellaneous	3.4	5.4	4.9	5.9	5.4
TOTAL	4.3%	4.2%	4.2%	4.0%	4.2%

Percentage Breakdown of U.S. Primary Energy† Consumption

Sector	1960	1970	1975	1980	1985
Residential/Commercial	21.1	19.2	17.6	16.2	15.0
Industrial	29.3	26.2	24.0	21.8	19.7
Transportation	24.3	24.0	23.9	23.3	22.6
Electric Utilities	18.8	24.6	28.2	32.2	35.5
Non-Energy & Miscellaneous	6.5	6.0	6.3	6.5	7.2
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%

* Includes fossil-fuel consumptions in each sector. The nuclear and water power outputs are converted to fossil-fuel input equivalents at average central station heat rates and are included in the electric utility sector.

Source: The historical volumes are from the U.S. Bureau of Mines, except for the 1970 electric utility estimate which is based on Federal Power Commission data for 1970. The BTU conversion factors also are from the Bureau of Mines except for modifications in the bituminous coal factors as follows: Electric utility coal is calculated at 24 million BTU's per short ton and all other bituminous at 26.2 million BTU's per ton.

TABLE III

U.S. TOTAL ENERGY CONSUMPTION PROJECTION BY CONSUMING SECTORS*

U.S. Total Energy Consumption in Trillions of BTU's

Sector	1960	1970	1975	1980	1985
Residential/Commercial	10,688	15,761	18,827	22,389	26,598
Industrial	14,362	20,056	23,193	26,774	30,921
Transportation	10,835	16,313	19,948	23,937	28,331
Non-Energy & Miscellaneous	2,916	4,058	5,279	6,705	8,930
Electricity Conversion	5,801	11,639	16,234	22,776	30,162
TOTAL	44,602	67,827	83,481	102,581	124,942

Average Annual Percent Change in U.S. Total Energy Consumption

Sector	1960-70	1970-75	1975-80	1980-85	1970-85 Projection
Residential/Commercial	4.0	3.6	3.5	3.5	3.6
Industrial	3.4	2.9	2.9	2.9	2.9
Transportation	4.2	4.1	3.7	3.4	3.7
Non-Energy & Miscellaneous	3.4	5.4	4.9	5.9	5.4
Electricity Conversion	7.2	6.9	7.0	5.8	6.6
TOTAL	4.3%	4.2%	4.2%	4.0%	4.2%

Percentage Breakdown of U.S. Total Energy Consumption

Sector	1960	1970	1975	1980	1985
Residential/Commercial	24.0	23.2	22.6	21.8	21.3
Industrial	32.2	29.6	27.8	26.1	24.7
Transportation	24.3	24.1	23.9	23.4	22.7
Non-Energy & Miscellaneous	6.5	6.0	6.3	6.5	7.2
Electricity Conversion	13.0	17.1	19.4	22.2	24.1
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%

* Table III differs from Table II in that electricity is included in the appropriate consuming sector. The conversion factor assumed for the use of electricity in each consuming sector is 3,412 BTU's per KWH, and the energy used by utilities for generation and transmission of electricity is shown in the electricity conversion category. Of course, there are other instances of energy conversion but these are included in the appropriate consuming sector.

Source: The historical volumes are from the U.S. Bureau of Mines except for the 1970 electric utility estimate which is based on Federal Power Commission data for 1970. The BTU conversion factors also are from the Bureau of Mines except for modifications in the bituminous coal factors as follows: Electric utility coal is calculated at 24 million BTU's per short ton and all other bituminous at 26.2 million BTU's per ton.

satellite towns. Shopping centers, service facilities and recreational activities are expected to expand rapidly, all of which will help to stimulate the growth in energy demand.

On the other hand, several new conditions will tend to retard the growth in this energy market: (1) The population mix is trending toward larger proportions of young adults, (2) new families are becoming smaller, and (3) costs of land and construction have risen substantially. These factors suggest that the recent trend toward smaller dwelling units will continue through the decade of the 70's. It is expected that new housing units will include a much larger proportion of apartments, in sharp contrast to conditions of the past 20 years when most new units were single-family dwellings.

The net result of these factors indicates that residential/commercial energy consumption (including electricity) will increase 3.6 percent annually over the 15-year forecast period, although its share of total energy will decline from 23.2 percent in 1970 to 21.3 percent by 1985. For fossil fuels only (Table II), the projected growth rate is 2.5 percent annually, with its share declining from 19.2 to 15 percent during the period.

b. Industrial

The growth in the industrial energy market shows a changing relationship to the level of industrial production. During the period 1947-1967, the industrial use of fossil fuels grew at a rate of less than one-half the industrial production growth rate, because of rapid improvements in the efficiency of fuel use and relatively larger purchases of electricity from utilities.

Beginning about 1968, however, the ratio of industrial fossil fuel consumption to the Nation's industrial output increased markedly. For the last 3 years, fuel demand advanced 3.8 percent per year whereas industrial production grew at a rate of only 2.2 percent. Although there are a number of causal factors, the following are believed to be the main reasons for departures from the long-term historical relationship:

- Efforts to eliminate industrial pollution of water and air were accelerated, which required additional energy use in manufacturing and mining operations.
- Energy-intensive industries recently enjoyed relatively high growth rates.
- Energy consumption was less sensitive to the business cycle downturn in 1970.

Balancing the many factors working toward fuel economy against those requiring greater consumption of energy, the task group projected industrial consumption at a somewhat lower rate than was experienced during the past decade. Industrial consumption of primary energy is projected at gradually declining growth rates that average 2.2 percent over the next 15 years. Expressed in terms of market share, the industrial component of total primary energy demand is estimated to decline from 26.2 percent in 1970 to 19.7 percent in 1985. The decline in market share is smaller, i.e., 29.6 percent to 24.7 percent when electricity is included in this consuming sector. In this case the estimated demand growth rate is higher, i.e., 2.9 percent per year.

c. Transportation

Since energy requirements for transportation in the United States are supplied almost entirely by oil, the detailed analysis of demand will appear in the Oil Subcommittee Report. This section will review some of the more general economic factors that determine the size of vehicle population, consumption per vehicle and other parameters of transportation demand.

Electricity is a very minor item in total transportation demand and does not affect the long-term projections, either in terms of growth rates or market share.

What were the main reasons for the fairly high growth rate (4.2 percent) for transportation energy consumption during the decade of the 1960's? A rapid growth in personal income has been a very important factor because it provides the means for increases in numbers of vehicles, larger cars, more power accessories and more travel miles--both by car and by aircraft.

Demographic patterns also have played significant roles in transportation trends. The dispersion of urban population from the city core into suburban rings has greatly expanded the need for transportation. Since this need could not be fully served by mass transit systems, urban change has created a substantial need for car ownership, both single and multiple, with an attendant increase in travel mileage. The age distribution of the population--in this case, a large increase in the "driving age" group during the 1960's--also added to the pressure for more cars-in-use and car-miles.

These demographic and economic trends are expected to continue during the next 15 years, but at somewhat reduced rates. Little change is foreseen in the trend toward a more widely dispersed urban population and, hence, in the need for private transportation. The programs for mass transit systems that have been developed or proposed are not of sufficient magnitude to affect significantly the need for automobiles before 1980. In fact, such mass transit systems can do little more than relieve extreme road and street congestion in some areas.

A variety of other factors also will affect the growth rate of motor fuel demand. Among those tending to increase motor fuel consumption, perhaps the most important are the proposed antipollution devices and, to a much lesser extent, additional power accessories on vehicles. The expected trend toward smaller, more economical cars will work in the opposite direction.

Apart from motor vehicles, the other major component of transportation energy is civilian aviation demand. It is expected that consumption volume will increase more rapidly in the future than in the past; however, the base is becoming so large that the percentage growth rate will gradually taper off to about 6 percent per year by 1985. For the entire 1970-1985 period, the average annual growth rate for civilian aviation demand is estimated at approximately 8 percent.

After examining the above-mentioned factors and many others, the task group concluded that the energy consumption of the transportation sector would experience growth rates of 4.1 percent, 3.7 percent and 3.4 percent for the periods 1970-1975, 1975-1980 and 1980-1985 respectively. Since these growth rates are lower than those projected for total energy demand, the transportation sector declines in relative share from 24.1 percent in 1970 to 22.7 percent in 1985.

d. Electric Utilities

Electric utilities now rank second in size among the energy consuming sectors shown in Table II, with about 25 percent of the 1970 total primary demand for energy. During the decade of the 1960's, the average annual increase in electricity sales, measured in kilowatt hours (KWH), was 7.4 percent while the fuel input growth rate was 7.2 percent--indicating that there was a small improvement in the electric generating and transmission efficiency.

The residential/commercial market is the utilities' largest customer for electricity and it offers the best prospects for future growth, especially in space heating and cooling. The industrial market for electricity is nearly as large and it also presents many growth opportunities. For the next 15-year period, the task group projected an average annual growth rate of 7.2 percent for total electricity requirements. Since the "heat rate" (i.e., number of BTU's required to produce 1 KWH, which is a rough inverse measure of fuel efficiency) is estimated to decline by a total of about 7 percent during the period, the growth rate for primary energy input by utilities is about 6.7 percent. The utilities' projected share of total energy is 35.5 percent, or nearly 11.0 percentage points higher than 1970.

In order to achieve such a growth rate, the electric utility industry will have to surmount a growing number of environmental roadblocks. The processes for securing rights-of-way for transmission line corridors and new sites for generating plants are becoming more lengthy and difficult. The projections shown in this report have assumed that public authorities and the utility industry will jointly improve, rationalize and expedite their methods of obtaining approval for new facilities.

The capital requirements for such a 15-year expansion will be huge--amounting to over $200 billion (in 1970 dollars) for generation and transmission. This is about three times the industries' total current (undepreciated) investment and more than three times the industries' total capital expenditures of the past 15 years. In addition, about $100 billion will be spent on distribution facilities.

e. Non-Energy and Miscellaneous

The non-energy sector includes all fossil fuels (chiefly petroleum) that are used as raw materials in the manufacture of chemicals and fertilizers, lubricants, greases, asphalts, coatings and similar products. The miscellaneous portion includes both energy and non-energy "unaccounted for" items.

The future growth rate for the total sector is estimated at 5.4 percent per year, on the average, and the fast-growth components are petroleum and natural gas used as chemical feedstocks. Based on this growth rate, the non-energy share of total energy will rise from 6 percent in 1970 to 7.2 percent in 1985.

3. Consumption by Geographical Areas

As an aid in identifying special energy problems that may differ among regions of the United States, energy projections have been developed for each of the five PAD Districts (see Table IV) and for selected Census Divisions (see Table V). The consuming sector breakdowns for each district are based on the primary energy classification described in Table II.

Although total primary energy demand will grow in all districts and in all consuming sectors, there are several significant geographical differences *relative* to the U.S. total. While PAD District I, in total, will grow at a slower pace than that of the Nation, it will be a composite of contrasting trends in New England, Middle Atlantic and South Atlantic subareas. Based on the expectation of a continuing shift of population, commerce and industry toward the South, the South Atlantic energy consumption outlook is for significant increases. New England and the Middle Atlantic, on the other hand, are expected to show relative declines in all consuming sectors.

The share of energy consumption in PAD District II (Middle West) is expected to decline in most markets while the District III (Southwest) share probably will be trending upward. As a result of population movements westward to the Mountain States and the West Coast, increasing shares of energy demand are projected for Districts IV and V.

TABLE IV

PAD DISTRICTS
GEOGRAPHIC BREAKDOWN OF U.S. PRIMARY ENERGY CONSUMPTION FORECAST
BY CONSUMING SECTORS
(Trillions of BTU's)

	1970	1975	1980	1985
District I				
Residential/Commercial	5,211	5,790	6,417	7,019
Industrial	4,716	5,190	5,652	6,044
Transportation	5,552	6,808	8,164	9,621
Electric Utilities	5,576	7,951	11,285	15,261
Non-Energy & Miscellaneous	787	955	1,140	1,607
TOTAL	21,842	26,694	32,658	39,552
District II				
Residential/Commercial	5,120	5,820	6,618	7,507
Industrial	6,336	6,994	7,641	8,387
Transportation	5,178	6,230	7,424	8,690
Electric Utilities	5,626	7,575	10,262	13,486
Non-Energy & Miscellaneous	1,023	1,283	1,576	2,063
TOTAL	23,283	27,902	33,521	40,133
District III				
Residential/Commercial	1,040	1,223	1,434	1,689
Industrial	4,681	5,390	6,188	7,030
Transportation	2,231	2,707	3,222	3,781
Electric Utilities	2,321	3,482	5,048	6,921
Non-Energy & Miscellaneous	1,806	2,508	3,359	4,465
TOTAL	12,079	15,310	19,251	23,886
District IV				
Residential/Commercial	376	442	517	620
Industrial	516	601	715	789
Transportation	488	597	716	875
Electric Utilities	467	659	924	1,242
Non-Energy & Miscellaneous	101	116	134	170
TOTAL	1,948	2,415	3,006	3,696
District V				
Residential/Commercial	1,247	1,458	1,683	1,933
Industrial	1,549	1,864	2,145	2,417
Transportation	2,833	3,563	4,344	5,247
Electric Utilities	2,705	3,858	5,477	7,453
Non-Energy & Miscellaneous	341	417	496	625
TOTAL	8,675	11,160	14,145	17,675

TABLE V

SELECTED CENSUS DIVISIONS
GEOGRAPHIC BREAKDOWN OF U.S. PRIMARY ENERGY CONSUMPTION PROJECTION
BY CONSUMING SECTORS*
(Trillion BTU's)

	1970	1975	1980	1985
New England				
Residential/Commercial	1,042	1,141	1,249	1,341
Industrial	297	311	322	326
Transportation	761	919	1,094	1,280
Electric Utilities	647	894	1,155	1,496
Mid-Atlantic				
Residential/Commercial	2,892	3,213	3,572	3,895
Industrial	2,792	3,031	3,267	3,469
Transportation	2,337	2,805	3,249	3,685
Electric Utilities	2,364	3,222	4,388	5,692
South Atlantic				
Residential/Commercial	1,277	1,436	1,596	1,783
Industrial	1,627	1,848	2,063	2,249
Transportation	2,454	3,084	3,821	4,656
Electric Utilities	2,565	3,835	5,742	8,073
East North Central				
Residential/Commercial	3,404	3,860	4,401	5,011
Industrial	4,414	4,689	4,960	5,303
Transportation	2,877	3,529	4,227	4,963
Electric Utilities	3,189	4,187	5,675	7,276

* Note: Energy consumption in these Census Divisions is not totaled because a breakdown of non-energy and miscellaneous uses is not available.

Chapter Two

Oil Task Group

Oil Demand

OIL DEMAND TASK GROUP

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OIL DEMAND TASK GROUP REPORT

ABSTRACT

Total domestic oil demand is estimated to increase from 14.7 million barrels per day (MMB/D) in 1970 to 26.0 MMB/D in 1985, an average annual increase (AAI) of 3.8 percent compared with that for total energy of 4.2 percent. The forecast demand for each main product group is shown in Table VI.*

TABLE VI

U.S. PETROLEUM DEMAND BY PRODUCT
(MB/D)

	1970	1975	1980	1985	AAI % 1970-85
Motor Gasoline	5,785	6,950	8,200	9,200	3.1
Kerosine Jet	720	1,168	1,747	2,404	8.4
Distillate	2,512	2,931	3,386	3,728	2.7
Residual Fuel Oil	2,235	3,068	3,833	4,272	4.5
Other	3,470	4,229	5,163	6,373	4.1
TOTAL	14,722	18,346	22,329	25,977	3.8%

Slightly more than half of oil demand is in the transportation sector. Projected oil demand by major consuming sector is shown in Table VII.*

Geographic breakdown of oil demand is influenced primarily by the distribution of population. The domestic demand is projected by geographic units in Table VIII.*

As a proportion of total Free World oil demand, U.S. demand will fall from 36.7 percent in 1970 to 30.9 percent in 1980.

*Detailed demand figures shown in this Abstract and in Chapters Two and Four do not include the increases in residual fuel oil demand reported in Volume One (see Extract in this Volume) to reconcile task group predictions of oil demand to the projections of total energy demand. These increases are 165 MB/D in 1975, 360 MB/D in 1980 and 400 MB/D in 1985.

TABLE VII

U.S. PETROLEUM DEMAND BY SECTOR
(MB/D)

	1970	1975	1980	1985	AAI % 1970-85
Transportation	7,838	9,647	11,774	13,801	3.8
Residential/Commercial	2,607	2,898	3,104	3,299	1.6
Industrial	1,500	1,839	2,256	2,683	4.0
Utilities	910	1,697	2,345	2,665	7.4
Petrochem Feedstocks	818	1,163	1,586	2,089	6.5
Other	1,049	1,102	1,264	1,440	2.1
TOTAL	14,722	18,346	22,329	25,977	3.8%

TABLE VIII

U.S. PETROLEUM DEMAND BY PAD DISTRICTS
(MB/D)

	1970	1975	1980	1985	AAI % 1970-85
District I	5,894	7,475	9,007	10,287	3.8
District II	4,110	4,982	5,999	6,895	3.5
District III	2,369	2,960	3,643	4,374	4.2
District IV	397	490	595	710	3.9
District V	1,952	2,439	3,085	3,711	4.4
TOTAL	14,722	18,346	22,329	25,977	3.8%

SUMMARY OF OIL DEMAND TASK GROUP REPORT

The Oil Demand Task Group projected demand for oil by market, geographical area and individual oil product, maintaining consistency with the guidelines provided by the Energy Demand Task Group.* The Oil Demand Task Group also made its own independent assessment of the supply of other fuels in each market and area.

*See Extract, *supra*, p. *xxiv*, for discussion of demand projections and adjustments made by the Coordinating Subcommittee in preparing initial appraisal supply/demand balance.

ASSUMPTIONS

Among the more important assumptions concerning the supply and demand of alternative fuels were that:

- Oil, despite an increasing proportion of imports, would not suffer from supply constraints and would therefore maintain or increase participation in markets, particularly electricity generation, where constraints on the supply of competing fuels were assumed.

- Potential gas demands are in excess of potential supply, and some demand would therefore have to be met by alternate fuels.

- The development of coal and nuclear sources of energy would be inhibited by environmental concerns and long lead times.

In developing these estimates it was assumed, as in other parts of the study, that existing U.S. policies would be unchanged, except that sufficient oil imports were assumed to be available to supplement domestic supplies as required.

TOTAL PRODUCT DEMAND

Demand for petroleum products is projected to rise to almost 26 MMB/D by 1985,* or an increase of 77 percent from today's requirements of about 14.7 MMB/D. This represents a compounded annual average rate of growth of 3.8 percent for the next 15 years compared with a 4.2 percent for all energy. The forecast growth rate for oil is slightly lower than the rate of 4.1 percent which prevailed over the last two decades.

1. Motor Gasoline

Motor gasoline is and will continue to be the single largest petroleum product on the basis of volume. In fact, demand for this one product will reach 9.2 MMB/D in 1985, or 3.4 MMB/D more than in 1970 (59-percent increase). Motor vehicle registration forecasts obviously play a significant role in arriving at the forecast for gasoline demand. These registrations will reach 178 million by 1985 compared to 109 million in 1970. At the same time, the move to smaller cars will accelerate. By 1985, it is expected that 4 million of the 178 million registered vehicles will be electrically propelled. But concurrent with this change will be offsetting factors of added comfort equipment and pollution control equipment that result in increased consumption of gasoline per conventional car.

Until recently, two grades of leaded motor gasoline have been the primary products of the petroleum industry. By 1975, however, forecasts of future motor gasoline indicate that the premium and regular fuels of today will become low- and/or no-lead fuels. Similar dramatic changes will be observed in the octane requirements of the vehicles forecast to be on the road in the future. In 1980 only 12 percent of the vehicles on the road will be of pre-1971 vintage. About half of these will be capable of using the improved (92-93 octane) lead-free gasoline. When these older cars are combined with the post-1970 vintage vehicles, 94 percent of the total 1980 fleet can burn lead-free gasoline. By 1985 almost 97 percent of the total fleet will be post-1970 models (172 million vehicles); all which are powered by gasoline (168 million) will be capable of using lead-free fuel.

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*Excluding upward adjustments made by the Coordinating Subcommittee. See Extract, *supra*, pp. *xxiv-xxv*, for details.

2. *Jet Fuels*

An increasing desire on the part of Americans for air travel, for pleasure as well as business, will result in a kerosine jet fuel growth of over 8 percent per annum from 720 thousand barrels per day (MB/D) in 1970 to 2.4 MMB/D in 1985. These increases may be somewhat surprising in view of current air congestion and ground transportation delays in and around some airports. Here the important fact is that these density factors apply to some, not all, airports. Indeed, 39 percent of the kerosine-type jet fuel is used in PAD District I and one-half of this is in the Middle Atlantic states. But there are numerous airports along the East Coast. A similar situation exists on the West Coast where the demand for kerosine jet fuel is about 30 percent of the total U.S. demand.

3. *Residual and Distillate Fuels*

Because of recent sulfur pollution regulations, together with a gain in electric demand of more than 7 percent per year, more and more residual fuel oil is required. This demand, in fact, will result in almost a twofold increase in the demand for residual fuel oil (from 2.2 MMB/D in 1970 to almost 4.3 MMB/D in 1985) over the next 15 years.

At the same time, demand for distillates is also growing rapidly. Most of the new demand is for heating purposes and for vehicles, especially diesel trucks, but a considerable portion is also to meet new peak shaving electric needs. For utilities, demand for distillate fuel oil is expected to climb substantially, growing from 66 MB/D in 1970 to 250 MB/D by 1985.

Total fuel requirements in the household and commercial market are expected to increase from 15.8 quadrillion BTU's in 1970 to 26.6 quadrillion BTU's by 1985, a growth rate of 3.5 percent per year. Within this combined market, households use about 70 percent of the natural gas and nearly 60 percent of the electricity that is consumed.

To understand the impact of electrical heating on the demand for petroleum products in the residential and commercial markets, it is necessary to bear in mind the concept of the total fuels required to meet these energy needs. Although a switch to electric heat might cause an apparent reduction in oil demand for household heating, it actually results in relatively little change in the total petroleum energy required. While direct heating oil consumption would be reduced, this would be largely offset by increased consumption of residual or distillate fuels in the generation of the increased electricity demand. The actual net effect on the total energy consumption would vary from circumstance to circumstance depending upon the relative impact of such factors as the fuels actually consumed by the individual electric utilities, the efficiency of the specific electric generation stations, as well as the relative efficiencies of the electric versus oil residential heating units, the effectiveness of insulation and other heat loss characteristics of the dwellings involved.

The surge in demand for electricity within the residential/commercial market will result from two major factors. First, large increases of young married couples (20 to 29 years of age) in the total population will bolster demand for electric heat. A recent survey shows that 44 percent of 18- to 29-year-olds would prefer electric heating, whereas less than 35 percent of those over 30 years of age indicated a preference for electric heat. Second, a large increase in air conditioning is predicted, since only about 40 percent of existing households now have such units. This trend will be further accelerated by continued growth of the population in the "sun belt" (e.g., Southeast, Southwest and Pacific Coast states).

In the coming years there will be significant changes in product quality, particularly in sulfur specifications, to meet more stringent environmental standards. It is likely that changes in sulfur dioxide emissions regulations will create very large increases in the demand for low-sulfur fuels. On the East Coast, utility residual fuel oil demand has soared from 430,000 barrels daily in 1968 to 780,000 barrels daily in 1970, an 81-percent increase in only 2 years. The Middle West (PAD District II) increased its residual fuel oil use from 13,000 barrels daily in 1968 to over 39,000 barrels daily in 1970. These trends, slightly modified, will continue and place new demands on refinery capacity and complexity.

This discussion of demand is based on existing or recently enacted Air Quality Regulations. If this trend spreads to other sections of the United States, which is believed likely, not only will even heavier demands be placed on petroleum fuels as a result of additional new Air Pollution Control Regulations, but these demands will be further intensified by shortages of other energy sources (such as gas) and/or delays in developing nuclear power. To the extent that future supply of natural gas is not sufficient to meet premium demands in the residential/commercial markets and industrial requirements, oil demands will be even greater than those presented in this chapter.* As discussed in the Supply and Logistics Section, major obstacles must be overcome to meet the petroleum products demand as projected, without even considering the potential impact of further revisions in environmental regulations or from shortages of natural gas.

4. *Other Products*

Demand for petroleum liquids as a raw material for manufacture of petrochemical derivatives and other so-called non-energy uses is a small but rapidly growing share of the total demand for petroleum in the United States--from 9.8 percent in 1960 to 11 percent in 1970 to 13 percent by 1985. Asphalt and road oil demand has also been strong, up 3.8 percent per annum in the past 10 years. Similar growth, resulting in part from completion of the interstate highway system by the end of 1978, is forecast for the 1970's and 1980's (for resurfacing, widening and safety improvements). A summary of the demand for these and other non-fuel products is shown in Table IX.

TABLE IX

DEMAND FOR OTHER NON-FUEL PRODUCTS
(MB/D)

	1970	1975	1980	1985
Lubricants	135	149	165	183
Asphalt and Road Oil	440	560	673	806
Petrochemical Feedstocks	818	1,163	1,586	2,089
Other	201	221	244	269
TOTAL	1,594	2,093	2,668	3,347

*See Extract, *supra*, pp. *xxiv-xxv*, for discussion of demand projections and adjustments made by the Coordinating Subcommittee.

DEMAND BY REGION

Recent trends in regional demand growths are projected to continue along the same general lines. Thus, demand for most products will continue to grow somewhat faster in the South and West than in the Middle Atlantic and New England areas.

The projected development of petroleum demand by PAD Districts is set out in Tables X and XI.

TABLE X

PETROLEUM DEMAND BY PRODUCT--DISTRICT I
(MB/D)

	1965	1970	1975	1980	1985
Motor Gasoline	1,578	2,003	2,400	2,820	3,140
Aviation Gasoline	30	13	11	14	19
Naphtha Jet	94	67	60	58	56
Kerosine Jet	119	280	451	672	922
Kerosine	141	122	115	116	142
Distillate	1,087	1,273	1,476	1,689	1,837
Residual	1,072	1,640	2,329	2,776	3,012
LPG	88	125	166	208	263
Petrochemical Feedstocks	57	70	108	194	290
Asphalt & Road Oil	113	119	137	165	197
Coke	30	32	39	55	83
Lubricants	46	53	59	65	72
Spec. Naphtha	23	23	25	28	31
Wax	5	6	7	9	11
Miscellaneous*	(18)	10	11	12	13
Still Gas	56	58	81	126	199
TOTAL	4,521	5,894	7,475	9,007	10,287

* Includes crude losses and other losses unaccounted for.

TABLE XI

PETROLEUM DEMAND BY PRODUCT--DISTRICT II
(MB/D)

	1965	1970	1975	1980	1985
Motor Gasoline	1,635	2,025	2,405	2,835	3,180
Aviation Gasoline	25	12	10	14	18
Naphtha Jet	47	42	38	36	34
Kerosine Jet	71	152	243	361	493
Kerosine	99	86	87	97	131
Distillate	630	754	865	975	1,065
Residual	189	211	296	420	483
LPG	201	307	400	475	561
Petrochemical Feedstocks	44	78	113	163	220
Asphalt & Road Oil	131	160	210	252	299
Coke	77	82	86	97	107
Lubricants	40	42	45	50	56
Spec. Naphtha	20	21	22	24	27
Wax	2	3	4	5	6
Miscellaneous*	(10)	--	--	1	2
Still Gas	113	135	158	194	213
TOTAL	3,314	4,110	4,982	5,999	6,895

* Includes crude losses and other losses unaccounted for.

TABLE XII

PETROLEUM DEMAND BY PRODUCT--DISTRICT III
(MB/D)

	1965	1970	1975	1980	1985
Motor Gasoline	566	733	900	1,080	1,240
Aviation Gasoline	32	15	12	15	20
Naphtha Jet	40	35	32	30	28
Kerosine Jet	33	55	91	139	194
Kerosine	17	44	47	54	74
Distillate	134	175	215	266	307
Residual	69	88	100	151	180
LPG	140	199	232	272	310
Petrochemical Feedstocks	387	635	892	1,162	1,492
Asphalt & Road Oil	53	71	95	109	131
Coke	73	73	83	89	93
Lubricants	22	21	24	26	29
Spec. Naphthas	28	28	30	33	36
Wax	2	3	4	4	5
Miscellaneous*	102	28	27	29	30
Still Gas	124	166	176	184	205
TOTAL	1,822	2,369	2,960	3,643	4,374

* Includes crude losses and other losses unaccounted for.

TABLE XIII

PETROLEUM DEMAND BY PRODUCT--DISTRICT IV
(MB/D)

	1965	1970	1975	1980	1985
Motor Gasoline	141	171	205	235	270
Aviation Gasoline	4	2	2	3	5
Naphtha Jet	7	7	7	6	5
Kerosine Jet	9	20	33	49	69
Kerosine	7	8	8	10	14
Distillate	60	72	89	111	130
Residual	30	31	39	50	59
LPG	18	28	36	46	58
Petrochemical Feedstocks	--	1	1	2	2
Asphalt & Road Oil	24	29	36	44	52
Coke	6	7	9	10	12
Lubricants	5	6	7	8	9
Spec. Naphthas	1	1	1	1	1
Wax	--	--	--	--	--
Miscellaneous*	(20)	2	2	2	2
Still Gas	12	12	15	18	22
TOTAL	304	397	490	595	710

* Includes crude losses and other losses unaccounted for.

TABLE XIV

PETROLEUM DEMAND BY PRODUCT--DISTRICT V
(MB/D)

	1965	1970	1975	1980	1985
Motor Gasoline	673	853	1,040	1,230	1,370
Aviation Gasoline	29	13	13	17	22
Naphtha Jet	80	94	83	80	77
Kerosine Jet	102	213	350	526	726
Kerosine	3	3	5	8	26
Distillate	215	238	286	345	389
Residual	248	265	304	436	538
LPG	36	43	55	72	114
Petrochemical Feedstocks	20	34	48	65	85
Asphalt & Road Oil	47	61	82	103	127
Coke	16	20	26	33	40
Lubricants	16	13	14	16	17
Spec. Naphthas	10	13	14	15	16
Wax	1	1	1	2	2
Miscellaneous*	--	7	10	11	13
Still Gas	66	81	108	126	149
TOTAL	1,562	1,952	2,439	3,085	3,711

* Includes crude losses and other losses unaccounted for.

FOREIGN DEMAND

Consumption of energy outside the United States must be considered in order to permit viewing U.S. needs in proper perspective. As the United States becomes increasingly short of indigenous supplies, U.S. markets will need to compete with *Free Foreign* markets for the available foreign supplies. A projection of Free Foreign demand by product was made, assuming no major changes in each country's governmental policies or economic parameters from those which existed prior to the February 1971 OPEC settlement. Resulting Free World population, energy and oil demand are summarized in Table XV.

While the Free World outside the United States is over ten times greater in population than the United States, per capita energy consumption is much lower. Accordingly, total energy and oil consumptions of the Free Foreign area were only 57 and 63 percent of the world total in 1970. These Free Foreign energy and oil demands are both projected to continue to grow at much faster rates than in the United States (6.1 and 6.6 percent versus 4.2 and 3.8 percent, respectively) as a result of more rapid growth in population and per capita consumption. By 1985 Free Foreign demands for energy and oil will have increased to 62 and 66 percent respectively.

Despite wide difference in the petroleum product demand pattern among countries making up the Free Foreign area, the aggregate composition of the Free Foreign demand barrel is projected to remain nearly the same, except for a slight decrease in the proportion of aviation fuels/distillates and a slight increase in the proportion of residual fuel oil (see Table XVI). This contrasts with the U.S. situation where the naphtha/gasoline proportion is near 40 percent, while residual fuel oil constitutes a much lower proportion (15 percent in 1970) but is forecast to increase to over 17 percent by 1980. On the average, the product distribution of Free Foreign demand is a reasonably good match with the distillation yield of products from average foreign crude oil.

TABLE XV

FREE WORLD POPULATION AND ENERGY AND OIL DEMAND

	Population			
	1970		1980	
	Millions	% of Total	Millions	% of Total
Free World ex U.S.	2,257	91.7	2,779	92.4
U.S.	205	8.3	228	7.6
Total Free World	2,462	100.0	3,007	100.0

	Energy (oil equivalents)			
	1970		1980	
	MMB/D	% of Total	MMB/D	% of Total
Free World ex U.S.	42.5	57.0	78.7	61.9
U.S.	32.0	43.0	48.5	38.1
Total Free World	74.5	100.0	127.2	100.0

	Oil			
	1970		1980	
	MMB/D	% of Total	MMB/D	% of Total
Free World ex U.S.	25.4	63.3	49.8	69.1
U.S.	14.7	36.7	22.3	30.9
Total Free World	40.1	100.0	72.1	100.0

TABLE XVI

DISTRIBUTION OF FREE FOREIGN DEMAND BY PRODUCT

	Percent of Free Foreign Oil Demand	
Product	1970	1980
Naphtha/gasoline	20.5	20.0
Aviation fuels/distillates	30.1	28.6
Residual fuel oil	39.0	40.2
Other	10.4	11.2
TOTAL	100.0	100.0

In the Free World outside the United States, demand for energy is projected to be supplied by the mix of primary fuels shown in Table XVII. Over the period, oil continues to increase its share of total energy supply from nearly 60 percent in 1970 to over 63 percent by 1980, principally due to the lack of growth projected for coal and timing restrictions on nuclear. It should be emphasized that these projections do not recognize the effects of the recent OPEC settlements, now and in the future, on both the economical and political aspects of interfuel competition.

TABLE XVII

FREE FOREIGN DEMAND FOR ENERGY

	1970		1980	
	MMB/D Oil Equiv.	% of Total	MMB/D Oil Equiv.	% of Total
Oil	25.4	59.6	49.8	63.4
Gas	2.8	6.6	8.5	10.7
Coal	10.2	23.9	11.2	14.2
Hydroelectric	3.9	9.2	6.1	7.8
Nuclear	.2	.7	3.1	3.9
TOTAL	42.5	100.0	78.7	100.0

Chapter Three

Oil Task Group

Oil Supply

OIL SUPPLY TASK GROUP

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OIL SUPPLY TASK GROUP REPORT

ABSTRACT

Assuming that the 14-year decline in domestic exploration and development activities levels out and continues at the average of the recent past, crude oil production (including condensate) will continue at the present level of about 9.5 MMB/D until 1975 when it is assumed that oil will start coming in by pipeline from the North Slope of Alaska. The rate will then increase to about 10.5 MMB/D by 1980, followed by a gentle decline to the end of the period in 1985. Production from the lower 48 states onshore will decline after reaching "immediately available" capacity in the early to mid-1970's, but will be partially offset by the increase in production from offshore areas and more than offset by North Slope production from 1975 to 1980. Condensate production will fall off as gas supply falters.

Surplus crude oil productive capacity has declined from about 3.75 MMB/D in the 1965-1967 period to about 1.5 MMB/D at present, which includes the 0.5 to 0.75 MMB/D of capacity not immediately available to producers from places such as the Elk Hills Naval Petroleum Reserve.

Although discovery of new oil is estimated to add 13.5 billion barrels of reserves during the period, the bulk of reserve additions (28.5 billion barrels) comes from the application of secondary and tertiary recovery processes.

Onshore drilling costs were projected upward 18 percent due to the trend toward deeper wells. Offshore drilling costs were estimated to increase 47 percent over the forecast period as drilling moves into deeper and deeper waters. Operating costs were projected to increase 11 percent with the trend toward more secondary and tertiary oil recovery. The investment costs of getting tertiary oil during the period 1971-1985 were predicted to increase 50 percent offshore to $1.50 per barrel and 67 percent onshore to $1.25 per barrel due to application of more expensive processes to less attractive prospects. These cost parameters, where relevant, were used in projecting the capital requirements developed in Chapter Five. All projected costs are expressed in 1970 dollars.

The estimated *Free Foreign* reserves now considered proved are sufficient to satisfy the Free Foreign market and also make up the deficit between U.S. demand and domestic supply over the next 15 years. Annual Free Foreign reserve additions are still coming on at a faster rate than demand is increasing.

The United States cannot expect to increase imports from Western Hemisphere sources appreciably during the forecast period. Venezuela, the major source in Latin America, failed to respond significantly to the demand surge created during the Middle East supply disruptions of 1967 and 1970. The termination of the major contract concession arrangements in the early 1980's casts further doubt on the reliability of Venezuela as a supply source. Canada's proved reserves decreased in 1970 for the first time since 1946, and although there is potential for development of major supplies in the frontier areas, the uncertainties, particularly with respect to timing, preclude placing much reliance on this source to significantly alter U.S. import requirements from overseas.

The United States will probably have to rely heavily on Eastern Hemisphere sources for a growing portion of its future crude oil supply. This will prevail

unless domestic exploration drilling and development activities are markedly accelerated, improved recovery methods are applied and pioneer efforts in synthetics are initiated.

The assessment of foreign supplies was completed prior to the 1971 OPEC settlements, the effects of which will be discussed in the subsequent work of the task group.

SUMMARY OF OIL SUPPLY TASK GROUP REPORT

A projection of domestic oil supply was made providing a forward extrapolation of the results expected if prevailing levels and profiles of activity are approximately maintained. This projection brings into focus changes in direction that might alter the oil supply position.

The domestic crude oil supply availability was projected for the 15-year period 1971-1985. Specific producing rate levels are indicated for the years 1970, 1975, 1980 and 1985. All cost projections for various types of operations are expressed in constant 1970 dollars.

Cost adjustment factors to properly account for the changing modes of future operations were developed for use by the Oil Logistics Task Group and the Joint Oil and Gas Task Group on Capital Requirements for Exploration, Development and Production. Associated gas discovered with new oil was furnished the Gas Supply Task Group. Projected lease condensate and gas plant liquids volumes were developed by the Gas Supply Task Group.

Projected results were aggregated into the following geographical regions: North Slope, "Lower 48" Onshore, Offshore (includes Alaska other than North Slope) and Total U.S.A.

A survey of the oil reserve situation in major foreign areas was also made to assist the Oil Logistics Task Group in assessing transportation and refinery needs.

PROCEDURAL APPROACH

The Oil Supply Task Group took the following procedural steps for development of the initial appraisal:

- American Petroleum Institute (API) reserve, development drilling and production statistics; American Association of Petroleum Geologists (AAPG) exploratory drilling statistics; Joint Association Survey (JAS) drilling cost statistics; Chase Manhattan Bank industry-cost studies; and the NPC Future Petroleum Provinces Study were utilized as the major sources of basic data.

- Relevant statistics were segregated into 14 geological regions (11 NPC regions subdivided to break out Offshore and North Slope) for analytical use. Results were then aggregated back into U.S.A. (excluding North Slope), Offshore, and "Lower 48" Onshore.

- Exploration and drilling activity levels for each region (footage drilled) were assumed to continue through 1985 at levels generally prevailing during the 1967-69 period. No shifts in activity from one area to another were assumed. These levels of projection were accepted even though this type of activity has been steadily declining. (Since drilling depth is increasing with time, the number of wells drilled per year will decline under a constant drilling footage assumption.)

- Original oil-in-place to be discovered for each of the NPC regions was related directly to the footage drilled. Barrels projected to be discovered and developed per foot drilled were based upon an extrapolation of actual experience since 1956.

- Reserve additions from new discoveries and extensions were calculated from original oil-in-place data, using recovery efficiencies for reservoir conditions unique to the regions analyzed based on experience and engineering judgment.

- Reserve additions from secondary and tertiary improved recovery methods were projected on the basis of history and task group estimates as to how fast and how effectively these different methods would be applied. Secondary recovery consists of methods of improving recovery efficiency to the equivalent of that accomplished by water displacement. Tertiary methods have the capability of going significantly beyond water displacement to bring about improved recovery.

- Production rate for each region was projected based on past history of its reserve to production ratio and generally increasing this rate to an R/P ratio of 8-10:1.

- Associated gas discoveries were related to new oil discoveries based upon gas/oil ratio history during the last 5 years.

- Drilling depths were estimated to increase gradually, based upon historic trends. The related costs per foot onshore were escalated accordingly. Footage costs for offshore wells were escalated on the basis of platform costs required for increasing depths of water.

- Costs for reserve additions due to future secondary and tertiary applications were estimated in such a manner that they could be added to historic exploration and development costs and thereby complete a more meaningful relationship with reserve additions in the industry. This, in effect, adds some operation-type costs to historical capital costs; these operation-type costs are heavily front-loaded to bring about the introduction of a new energy source into a reservoir. The levels of these reserve-addition costs were estimated dependent upon the mix of various types of secondary and tertiary recovery methods that that would gradually be applied over the 15-year period.

- The prevailing levels of production operating costs were adjusted upward to recognize the increasing mix of secondary and tertiary operations versus primary operations.

- The initiation date for North Slope production and the projected level of such production were both assumed to be a function of the Trans-Alaska Pipeline system--i.e., its completion date and the capacity of the line, along with the downstream capacity to move the oil to U.S. markets. Following consultation with company representatives familiar with the North Slope pipeline situation, it was assumed for purposes of this initial appraisal that pipeline operations would commence in 1975 and that the capacity of the line would accommodate 2 MMB/D of production by 1980.

DISCUSSION

Reserve-addition estimates are the key to projected crude oil producing rates in the "Lower 48" Onshore and Offshore. The proved plus expected future reserve additions for the North Slope are estimated to be adequate to support the forecast throughput rate for the projected crude oil pipeline (beginning in 1975 at 600 MB/D and growing to a capacity of 2,000 MB/D by 1980).

The mix of projected crude oil reserve additions (excluding North Slope) is shown in Table XVIII and Figure 3. The secondary and tertiary reserve additions shown include improved recovery from both the resource base discovered prior to 1970 and the estimated future discoveries of oil included in the forecast.

TABLE XVIII

CRUDE OIL RESERVE ADDITIONS DURING PERIOD
(Billions of Barrels)

	New Oil	Secondary	Tertiary	Total
1970-74 Incl.	4.9	6.0	2.1	13.0
1975-79 "	4.4	6.0	3.8	14.2
1980-84 "	4.2	5.4	5.2	14.8

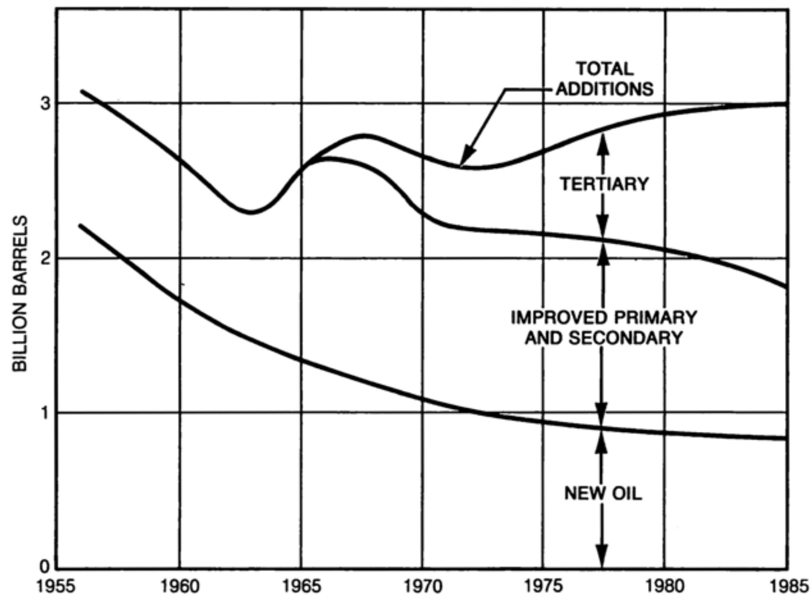


Figure 3. U.S.A. Annual Reserve Additions (Excluding North Slope).

Associated gas reserve additions resulting from new oil discoveries are projected in Table XIX.

TABLE XIX

ASSOCIATED GAS RESERVE ADDITIONS

	New Oil Reserves Added (Billion bbl)	Associated Gas Added (TCF)	Ratio of Discovered Associated Gas to New Oil Reserves Added (CF/B)
1970-74 Incl.	4.9	6.69	1,370
1975-79 "	4.4	5.86	1,330
1980-84 "	4.2	5.38	1,280

Projected supplies of domestic crude and condensate are shown in Table XX.

TABLE XX

PROJECTED PRODUCTION--ALL SOURCES
(MMB/D)

	Total U.S.A.			U.S.A. Without North Slope		
	Crude Oil	Condensate*	Total	Crude Oil	Condensate	Total
1970	9.10	0.37	9.47†	9.10	0.37	9.47
1975	9.15	0.38	9.53	8.55	0.38	8.93
1980	10.10	0.33	10.43	8.13	0.30	8.43
1985	9.87	0.24	10.11	7.90	0.21	8.11

* Includes Lease Condensate.
† API source; U.S. Bureau of Mines shows 9.63.

The following bar chart portrays significant trends by geographic areas within this projected profile. The condensate production for the total U.S.A. is shown as a separate segment at the top of each bar. All other bar intervals constitute the crude oil production trends.

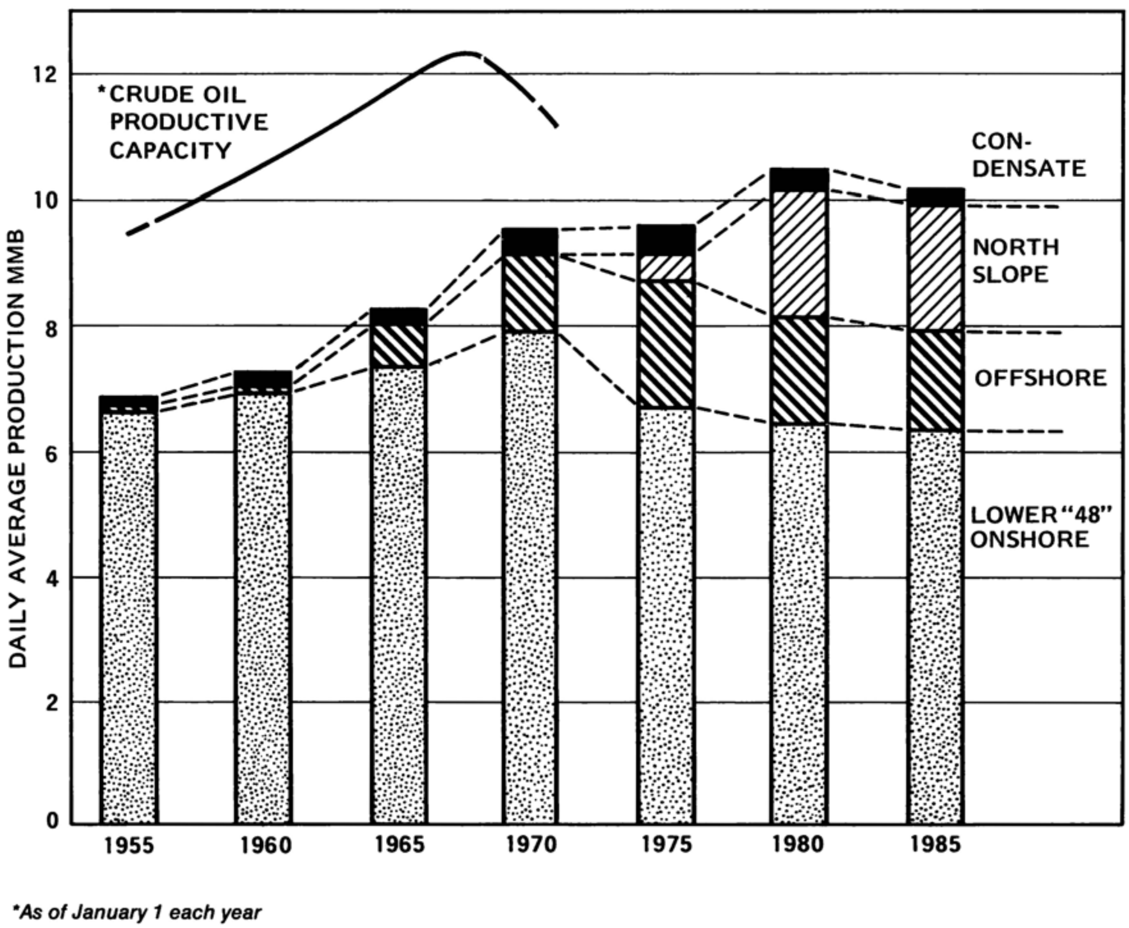


Figure 4. U.S.A. Oil Supply.

Crude oil productive capacity (excluding North Slope) is taken directly from NPC (1955-1965) and API (post-1965) statistics. Surplus capacity has declined from about 3.75 MMB/D in the 1965-1967 period to about 1.5 MMB/D in late 1970. This surplus capacity includes some 0.5 to 0.75 MMB/D which is not available to producers for various reasons (such as the Elk Hills Naval Petroleum Reserve). With these possible exceptions, all spare productive capacity is expected to be used up in the next few years.

One important aspect of the projection is the quantification of production from oil fields that will be discovered during the next 15 years. This is a function of future exploration and drilling activity and is reflected in Table XXI and Figure 5.

TABLE XXI

PRODUCTION FROM FUTURE DISCOVERABLE CRUDE OIL SOURCES
EXCLUDING NORTH SLOPE
(MMB/D)

	"Lower 48" Onshore	Offshore	Total
1975	0.67	1.13	1.80
1980	0.90	1.35	2.25
1985	1.10	1.55	2.65

These supply trends from both 1970 proved reserves and anticipated future discoveries are repeated on the following chart to put them in perspective.

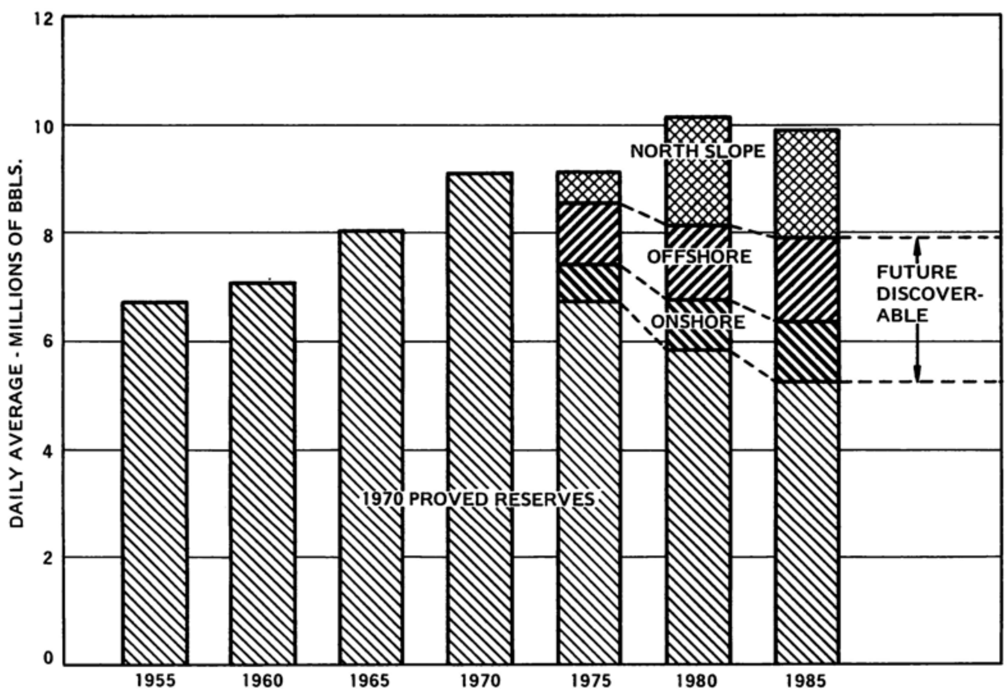


Figure 5. Total U.S.A. Crude Oil Production (Excluding Condensate).

The projection of crude oil supply is related to three significant factors. Two of these, the discovery of new oil (excluding North Slope) and the installation of a transportation system to handle North Slope discovered crude oil, are reflected in the foregoing chart. The third factor is the improvement in recovery efficiency from past discoveries in the rest of the United States. As is indicated in Figure 6 (p. 34), recovery efficiency is expected to increase from about 30 percent in 1970 to over 37 percent in 1985. The projection of oil production from past discoveries shown in Figure 5 incorporates the effects of this increase in recovery efficiency.

Total production for each of the 5-year periods considered in the initial appraisal is also necessary. This is shown in Table XXII.

TABLE XXII

PRODUCTION FROM ALL SOURCES DURING PERIOD
(Billions of Barrels)

	U.S.A.--Excluding North Slope				North Slope			Total U.S.A.		
	Oil		Cond.	Total	Oil	Cond.	Total	Oil	Cond.	Total
	Onshore	Offshore								
1970-74 Incl.	13.3	4.0	0.8	18.1	0	0	0	17.3	0.8	18.1
1975-79 "	11.9	3.2	0.6	15.7	2.6	0	2.6	17.7	0.6	18.3
1980-84 "	11.7	3.1	0.5	15.3	3.6	0	3.6	18.4	0.5	18.9

Historical cost factors were adjusted for use in the initial appraisal, as shown in Tables XXIII and XXIV. These are real cost increases in 1970 dollars, not inflation factors.

TABLE XXIII

COST ADJUSTMENT FACTORS
(Total Costs per Foot Drilled)

Onshore (because of increasing depth)	Average Well Depth (feet)	Cost per Foot Drilled (Multiplier)
1967-69 Incl. (Cost Base)	4,300	1.00
1970-74 "	4,800	1.06
1975-79 "	5,450	1.12
1980-84 "	6,250	1.18
Offshore (because of platform costs in increasing water depth)	**Average Water Depth (feet)**	**Cost per Foot Drilled (Multiplier)**
1967-69 Incl. (Cost Base)	170	1.00
1970-74 "	230	1.10
1975-79 "	300	1.23
1980-84 "	400	1.47

TABLE XXIV

COST OF RESERVE ADDITIONS
FROM SECONDARY AND TERTIARY INSTALLATIONS*
(Per Barrel Committed Cost
to Add Energy to Reservoir†)

	Onshore		Offshore	
	Secondary	Tertiary	Secondary	Tertiary
1970-74 Incl.	25¢	$ .75	50¢	$1.00
1975-79 "	25¢	1.00	50¢	1.25
1980-84 "	25¢	1.25	50¢	1.50

* Excluding operating costs.

† E.g., in water flooding, includes cost of developing source of water, treating and distributing to injection wells and injection pumps; for tertiary operations, includes cost of chemicals, sources of heat or compressors, etc.

PRODUCTION OPERATING COSTS

Carrying on the "prevailing level of activity" will call for some adjustment in overall cost as related to levels at the beginning of the forecast period. The increasing application of tertiary onshore and deeper water operations more distant from shore combine to require some escalation.

Multipliers for application to Total U.S.A. (excluding North Slope) operating costs are shown in Table XXV.

TABLE XXV

ADJUSTMENTS IN OVERALL COSTS

	Multiplier
1969 (Cost Base)	1.00
1970-74 Incl.	1.05
1975-79 "	1.09
1980-84 "	1.11

The capital requirements forecast resulting from application of these multipliers to 1967-1969 base cost numbers is indicated in Table XXVI.

TABLE XXVI

SUMMARY OF THE CAPITAL REQUIREMENTS NEEDED TO CARRY ON THE OIL DEVELOPMENT AND PRODUCTION ACTIVITY PROJECTED IN THE INITIAL APPRAISAL
(Billions of Dollars)

Year	Drilling Cost	Other Capital Costs*	Secondary & Tertiary Capital Costs	Investment Extension†	Investment
Actual					
1960	Developed from Chase Manhattan Series				2.845
1965					2.915
1970					2.800
1967-69 (Base)	2.15	1.01	0.50	3.66	3.16
Projected (1970 Dollars)					
1971	2.27	1.01	0.56	3.84	3.49
1972	2.30	1.01	0.63	3.94	3.59
1973	2.33	1.01	0.70	4.04	3.69
1974	2.36	1.01	0.77	4.14	3.79
1975	2.39	1.01	0.86	4.26	3.91
1976	2.42	1.01	0.97	4.40	4.05
1977	2.46	1.01	1.07	4.54	4.19
1978	2.49	1.01	1.18	4.68	4.33
1979	2.53	1.01	1.28	4.82	4.47
1980	2.57	1.01	1.39	4.97	4.62
1981	2.61	1.01	1.49	5.11	4.76
1982	2.65	1.01	1.60	5.26	4.91
1983	2.70	1.01	1.70	5.41	5.06
1984	2.74	1.01	1.81	5.56	5.21
1985	2.79	1.01	1.91	5.71	5.36

* Includes geology, geophysical, lease rental and lease bonus (held constant in accordance with the basic assumption of a constant activity level).

† In the actual capital costs for the base period 1967-69, the Chase Manhattan series included approximately $0.35 billion allocated to secondary and tertiary recovery. This had to be subtracted in order to make the projected capital costs comparable to the historical data. Otherwise, the $0.35 billion would have been counted twice. (Thus, column 5 minus $0.35 billion equals column 6 for the projected years.)

INTERPRETATION AND COMMENTS

The complete methodology and detailed work sheets are included in the Oil Supply Task Group Report. This summary discussion will highlight significant aspects of the analyses and interpret their relevance in relation to projected results.

CRUDE OIL SUPPLY--OVERALL

This projection shows that original oil-in-place discovered increased during the 15-year period (see Table XXVII). Along with this discovery trend the projection calls for an increase in cumulative recovery efficiency as reflected in Table XXVIII. These trends are also shown in Figure 6.

TABLE XXVII

CUMULATIVE ORIGINAL OIL-IN-PLACE DISCOVERED
(Billions of Barrels)

	U.S.A. (Excl. North Slope)	North Slope	Total U.S.A.
Dec. 31, 1969	396	24*	420
Dec. 31, 1984	437	(24)†	461
Total Ultimate Discoverable	677	50	727

* Not officially reported until December 31, 1970.

† No forecast was made of additional discoveries during the 15-year period. No doubt some more will be made; however, this area's production rate will be limited by transportation facilities rather than by reserves.

TABLE XXVIII

CUMULATIVE RECOVERY EFFICIENCY--U.S.A. EXCLUDING NORTH SLOPE

End of Year	Recovery Efficiency Percent
1955	25.21
1969	30.28
1984	37.03

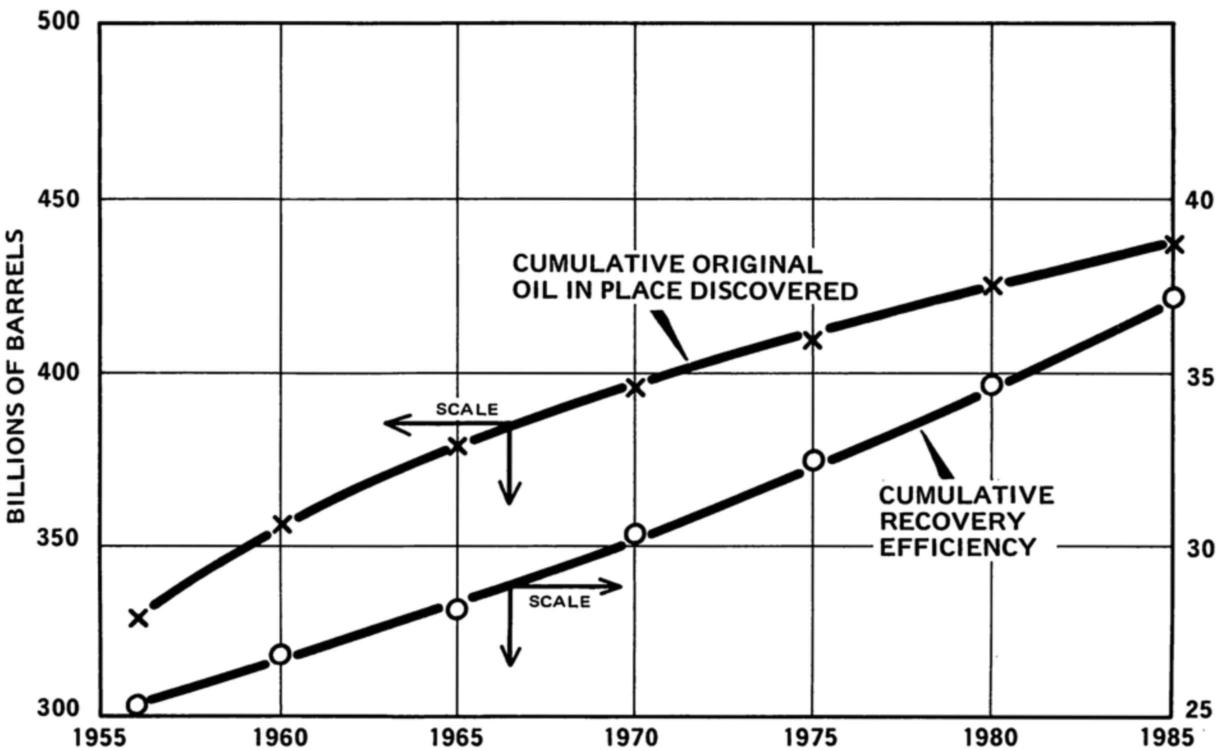


Figure 6. Total U.S.A. (Excluding North Slope).

Two observations are notable:

- The flattening of the original oil-in-place cumulative discovery curve is an undesirable trend. This has to be improved or crude oil supply will falter at an accelerating rate after new recovery methods are fully applied.

  The projected discovery rate is only 2.75 billion barrels per year. At this rate it would take almost a century to find the remaining oil-in-place estimated in the NPC's *Future Petroleum Provinces* report to be discoverable. This appears to be intolerably slow in view of the Nation's rapidly increasing need for energy supplies.

- The accelerated increase in cumulative recovery efficiency during the 15-year period of projection is believed to be realistic. Nevertheless, it will require a highly sophisticated effort on the part of management and technologists if it is to be achieved; and the economic incentives are marginal under the initial appraisal assumptions.

CRUDE OIL SUPPLY FROM PAST DISCOVERIES

Projections of this supply are controlled essentially by reserve additions due to secondary or tertiary recovery activity. During the historic period 1956-1969 inclusive, reserve additions of this type (API Revisions) have been playing an increasing role in the U.S.A. reserve-addition profile (Figure 7).

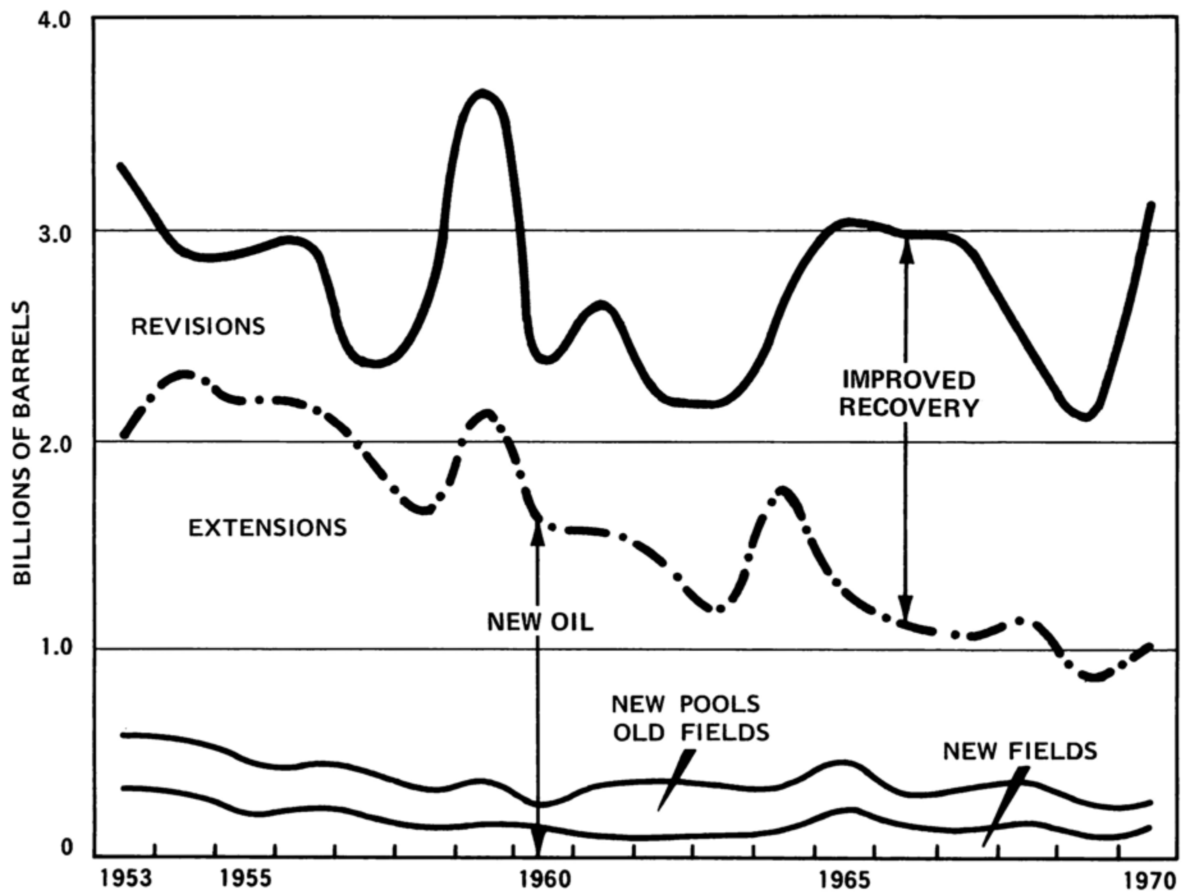


Figure 7. U.S.A. Crude Oil Supply Reserves, Year-End Additions (Excluding North Slope).

Part of the reserve additions from revisions reflected in Figure 7 have come from improved primary recovery methods. Secondary and tertiary cannot be given the full credit. However, in the future, most of this type of reserve addition will be due to improved recovery methods brought about by secondary or tertiary operations.

During the projection period the contribution from secondary and tertiary recovery activity is shown to take on a proportionately heavier load (see Figure 3, p. 28).

The expected reserve additions from secondary and tertiary activity were estimated using performance history and reservoir characteristics unique to each region and the latest engineering technology. The rate of application of these techniques is based upon judgment of the Oil Supply Task Group.

The rate of oil production from past discoveries was projected partially on past performance but with the objective of moving toward and operating within a sustained reserve/production ratio of 8-10:1; i.e., 8 to 10 years of reserves at the projected producing rate.

CRUDE OIL SUPPLY FROM FUTURE DISCOVERIES

This projection is a function of the oil-in-place discovery rate. Such a projection is fraught with many "ifs." Oil-in-place discovered is attributed, in the final analysis, to two measurable activities, exploration drilling and development drilling.

In the API reserve category, "new oil" reserve additions accrue to exploration drilling primarily from the discovery of new fields and new pools and to development drilling which brings in reserves from extensions to previously discovered sources (see Figure 7).

Reserve additions from these past drilling activities were brought in at estimated primary recovery efficiency levels estimated with the best technology at the time. This can vary from a low of perhaps 10 percent to a high of around 50 percent depending on the type of field, the natural energy source, etc.

Original oil-in-place discovered, however, is independent of the anticipated recovery efficiency and constitutes the discovered resource base to which all future activity must be addressed.

Two key judgments on appropriate methodology were:

- The historic relationship between total oil-in-place discovered and total footage drilled as a function of time would be developed. Trends so established would then be extrapolated for use in the projection period.

- The 1967-1969 levels of annual drilling rate (drilling footage) for each region having been established, this level of drilling activity would be projected to continue during the 1970-1985 period.

The "oil finding rate" per foot drilled was extrapolated into the projection period versus time, then multiplied by the annual footage drilled. This constitutes a measure of the total oil-in-place discovered. This was developed for each region and then aggregated into the "Lower 48" Onshore, Offshore and Total U.S.A. The North Slope was not analyzed in this manner; it was assumed that North Slope past and future discoveries would yield adequate reserves to supply the capacity of the transportation systems during the projection period.

The aggregated results for the United States that flow from these procedural determinations is reflected in Figures 8 and 9.

Figure 8 shows the drilling activity history for the Total U.S.A. Trends in each region vary; this is the composite. It is obvious that the decision to maintain a flat level of activity throughout the projection period would tend to make the projection optimistic in the face of the declining history. Nevertheless, the task group thought this was more suitable for determining the effects of future changes on oil supply than to project on a declining basis, the trend of which would have shown all drilling activities ceasing in the mid-1980's.

Figure 9 shows for the Total U.S.A., "Lower 48" Onshore and Offshore the aggregate regional results reflecting oil-in-place discovered per foot drilled as related to time. It is this type of result, unique for each region, that was multiplied by the footage drilled to make the discovery projection.

Also noted on Figure 9 are the 1969 average costs per foot of drilling for the three major groupings of results. Costs in individual regions vary considerably more than these averages indicate.

When the task group made its basic determination, it was recognized that this projection would reflect the past composite thinking of the industry on distribution of effort by regions. It tacitly assumes that there would be no change in this direction of thinking. This very likely will not be true. There are many other factors also that direct drilling effort of the industry to various regions. In oil exploration, significant discoveries in new basins or new areas quickly change the direction of effort in various segments of the industry. The task group, however, decided not to try in the initial appraisal to anticipate this type of change in direction.

While this methodology may result in an optimistic prediction, the projection of drilling activity used in the initial appraisal for some regions could prove to be uneconomic; effort that might have been expended in such regions would be redirected to more attractive areas if leases were available. This improved selectivity would tend to offset the optimistic aspect introduced by the assumptions on the drilling activity level used in the initial appraisal; this concept will be examined in more detail in future work.

The recoverable reserves associated with the newly discovered oil-in-place were projected and the rate of production timed by the same methodology employed in projecting crude oil supply from the past discoveries (i.e., an estimate of primary reserves is put on the books each year; after performance history has a chance to define the reservoir, secondary is added; after a period of time tertiary is included). Generally, primary recovery carried the producing rate for the first 5 years of the projection period; secondary was employed in the second 5 years; then subsequently tertiary, if applicable, in the third 5-year period.

GENERAL

While the methodology and many of the details are included in the full Oil Supply Task Group Report, Figure 10 and Tables XXIX and XXX provide a basic understanding of this projection; they are a map showing the regions used in the projection, a tabulation showing the discovered and potential discoverable oil-in-place in the United States and a table showing projected production for each region for each of the three 5-year periods.

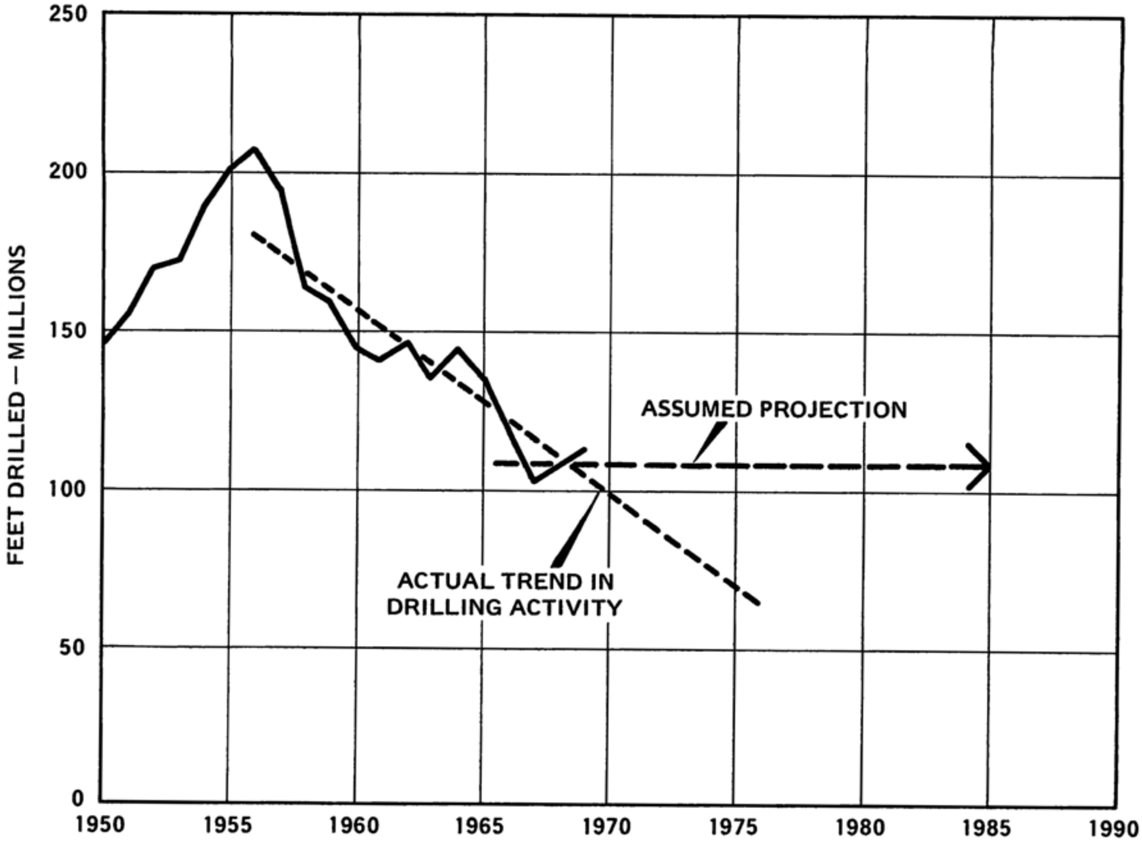


Figure 8. Oil Well Drilling Activity, Total U.S.A.

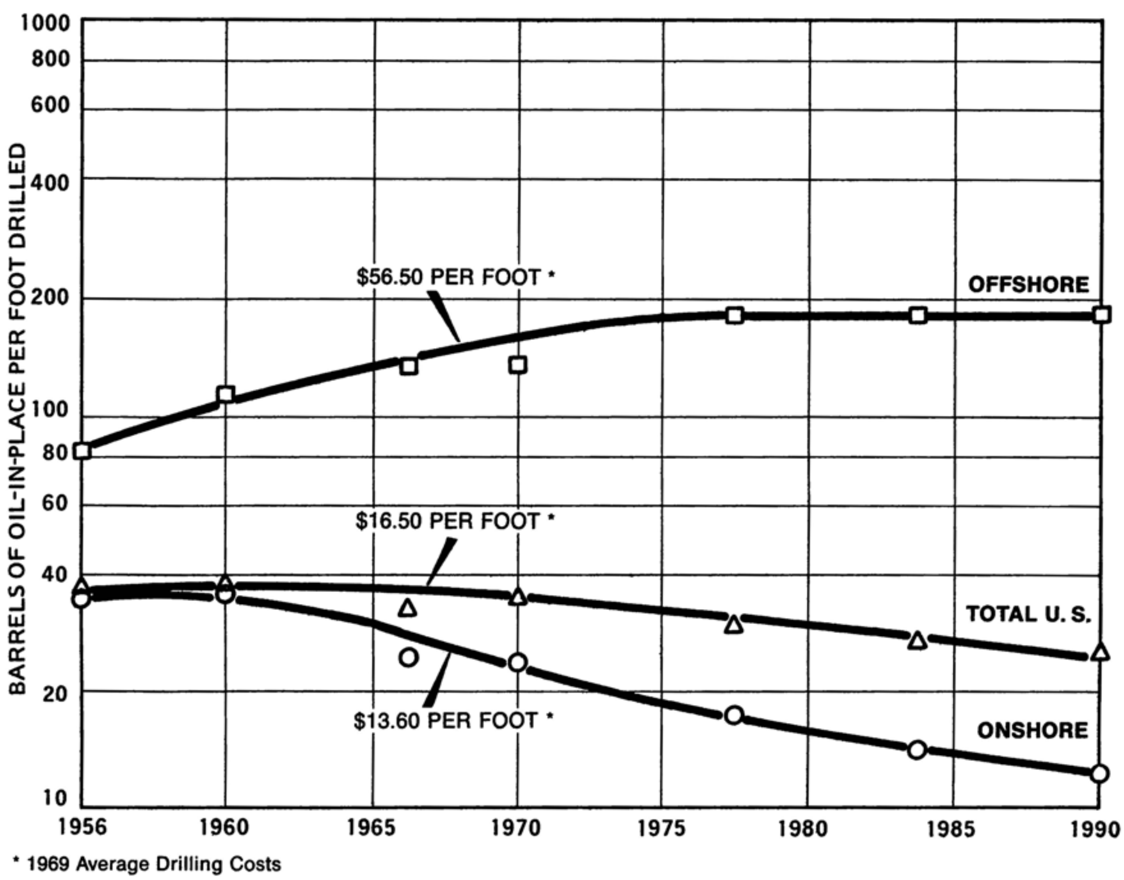
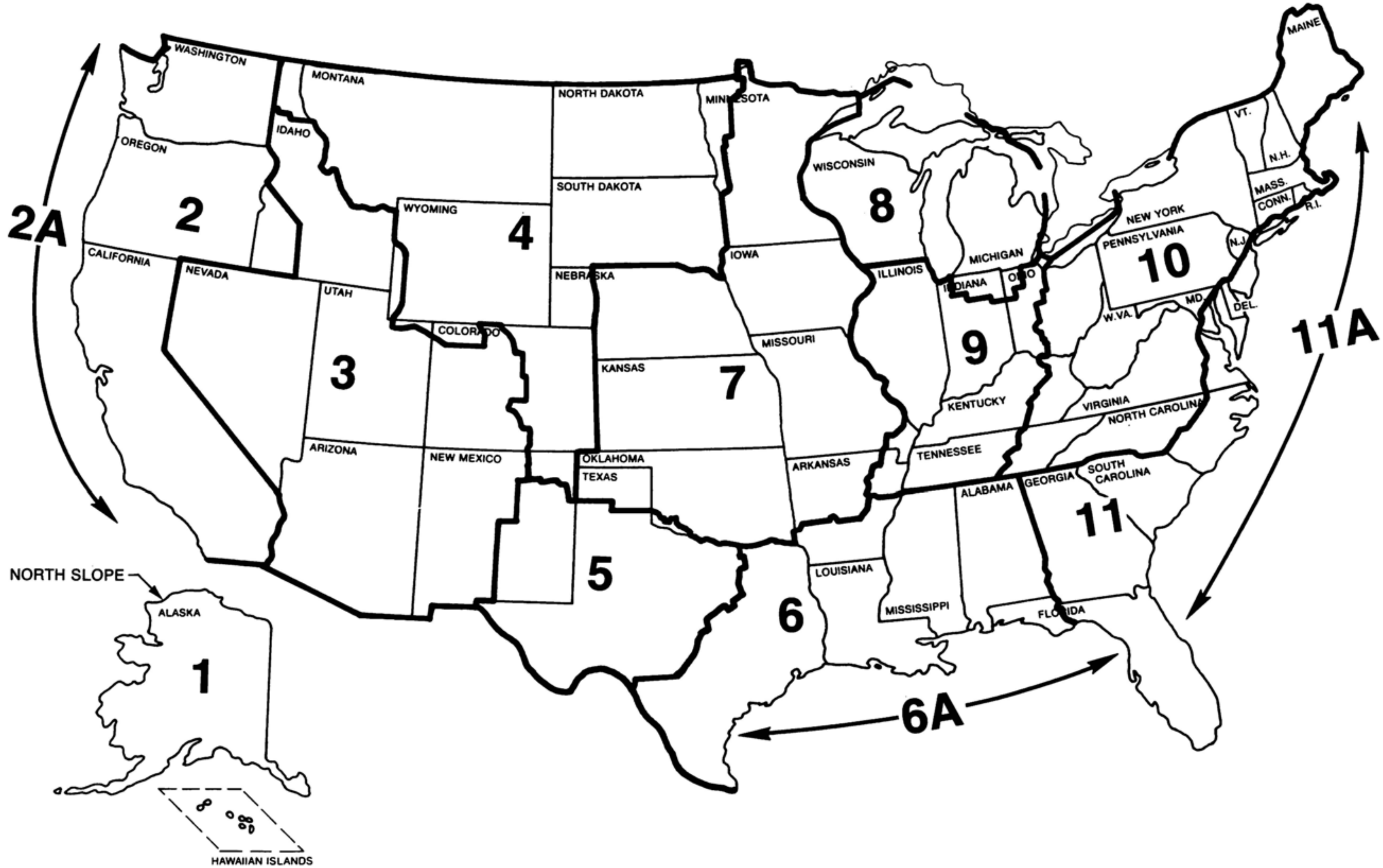


Figure 9. Oil Finding Rate.



Regional Boundaries: Region 1—Alaska and Hawaii, except North Slope; Region 2—Pacific Coast States; Region 2A—Pacific Ocean, except Alaska; Region 3—Western Rocky Mountains; Region 4—Eastern Rocky Mountains; Region 5—West Texas and Eastern New Mexico; Region 6—Western Gulf Basin; Region 6A—Gulf of Mexico; Region 7—Midcontinent; Region 8—Michigan Basin; Region 9—Eastern Interior; Region 10—Appalachians; Region 11—Eastern Gulf and Atlantic Coast; Region 11A—Atlantic Ocean; and North Slope Region.

Source: NPC *Future Petroleum Provinces of the United States* (July 1970).

Figure 10. Petroleum Provinces of the United States.

TABLE XXIX

API-NPC DISCOVERED AND DISCOVERABLE
OIL-IN-PLACE BY NPC REGIONS

Region Number	Name	(Millions of Barrels) API Proved Oil-in-Place 12-31-69	Cumulative Production 12-31-69	Estimated Ultimate Recovery	(Billions of Barrels) NPC Median Estimate of Future Discoverable OIP	Total of Discovered and Discoverable Oil-in-Place
1	Alaska & Hawaii	2,816	234	666	56.6	59.4*
2	Pacific Coast States	82,365	15,016	19,278	70.0	152.4†
3	Western Rocky Mountains	5,554	1,069	1,546	38.1	43.6
4	Eastern Rocky Mountains	23,216	4,824	6,533	29.2	52.4
5	West Texas & Eastern New Mexico	104,675	17,326	24,797	46.9	151.6
6	Western Gulf Coast	88,726	28,781	41,188	55.8	144.5‡
7	Mid-Continent	57,818	15,632	17,832	5.6	63.4
8	Michigan Basin	1,836	577	629	1.3	3.1
9	Eastern Interior	9,560	3,241	3,555	4.3	13.9
10	Appalachians	18,924	3,314	3,635	0.6	19.5
11	Eastern Gulf & Atlantic Coasts	17	2	4	23.6	23.6§
	TOTAL	395,507	90,016	119,663	332.0	727.4

* Allocated: 50.0 B bbls. North Slope.
9.4 B bbls. Region 1.

† Allocated: 100.4 B bbls. Region 2.
52.0 B bbls. Region 2A.

‡ Allocated: 111.5 B bbls. Region 6.
33.0 B bbls. Region 6A.

§ Allocated: 11.8 B bbls. Region 11.
11.8 B bbls. Region 11A.

TABLE XXX

TOTAL U.S.A.--FUTURE PRODUCTION OF CRUDE OIL
BY REGIONS AND PAD DISTRICTS
(Billions of Barrels)

Region		1970-1974	1975-1979	1980-1984
North Slope		0	2.6	3.6
1		.574	.586	.616
2		1.903	1.915	1.979
2A		.3975	.2679	.2755
3		.273	.219	.191
4		1.022	.816	.773
5		3.796	3.360	3.161
6		4.120	3.925	4.088
6A		3.017	2.328	2.164
7		1.69	1.28	1.08
8		.0574	.0131	.0170
9		.249	.214	.218
10		.20	.20	.19
11		.00144	.00082	.0007
11A		0	0	0
	TOTAL	17.30034	17.72482	18.3532
PAD District				
I		.20144	.20082	.1907
II		2.0804	1.5741	1.378
III		10.948	9.625	9.423
IV		1.196	.956	.891
V		2.8745	5.3689	6.4705
	TOTAL	17.30034	17.72482	18.3532

FOREIGN OIL SUPPLY TO 1985

There is no way of precisely determining or estimating the amount of undiscovered oil in the world as of any given point in time. Even the amount of oil in accumulations already discovered is very imperfectly known. However, as the general public has more and more come to recognize that oil is a natural resource of finite volume, curiosity as to how much oil is left has tended to increase. Distinguished geologists and petroleum engineers have periodically obliged this curiosity by publishing estimates of total oil-in-place and original oil-in-place in known reservoirs. There are a number of such estimates; they are generally based on a variety of assumptions and methods which arrive at understandably different results and conclusions. Common to these estimates is the fact that each reflects an informed opinion that the worldwide oil resource potential remaining to be discovered and developed is huge.

A brief discussion based on a recent representative sample of such estimates demonstrates this huge potential. In a U.S. Geological Survey Circular published in 1965 by the Department of the Interior, Mr. T. A. Hendricks estimates there are 10,000 billion barrels of total oil in the ground in the world. Of this total, he estimates about 6,200 billion barrels will be ultimately discovered and allocates these volumes by areas as shown in Table XXXI, columns 1 and 2. A paper presented by Messrs. P. D. Torrey, C. L. Moore and G. H. Weber at the 6th World Petroleum Congress titled "World Oil Resources, 1963" included an estimate of the original oil-in-place in known reservoirs as of January 1, 1962. This latter estimate, when related to Hendricks' total oil-in-place and ultimate discovery estimates, gives a measure of relative potential remaining by major world areas. The Torrey, Moore and Weber estimate is shown in Table XXXI, column 3. Mr. D. C. Ion of the British Petroleum Company, in a paper presented at the 7th World Petroleum Congress titled "The Significance of World Petroleum Reserves--1967," updated the Torrey, Moore and Weber paper. This calculated update is shown in Table XXXI, column 4.

TABLE XXXI

WORLD CRUDE OIL-IN-PLACE
DISCOVERABLE AND DISCOVERED
(Billions of Barrels)

	Existing*	Discover-able†	Discovered 1-1-62‡	Discovered 1-1-66§
U.S.A.	1,600	1,000	346	386
Canada, Mexico, Central America and Caribbean	500	300	50	77
South America (Incl. Venezuela)	800	500	214	238
Total W. Hemisphere	2,900	1,800	610	701
Europe	500	300	21	26
Africa	1,800	1,100	56	139
Middle East (Excl. Turkey)	1,400	900	793	928
S. Asia	200	100	7	8
U.S.S.R., China, Mongolia	2,900	1,800	90	122
Indonesia, Australia, Etc.	300	200	21	25
Total E. Hemisphere	7,100	4,400	988	1,248
TOTAL WORLD	10,000	6,200	1,598	1,949

* Total oil-in-place (Hendricks, 1965).
† Total discoverable oil-in-place (Hendricks, 1965).
‡ Original oil-in-place in known reservoirs as at 1-1-62 (Torrey, Moore and Weber, 1963).
§ Hypothetical calculation of original oil-in-place in reservoirs as known at 1-1-66 (D.C. Ion, 1967).

The timing and extent to which this huge oil potential will be found and recovered is impossible to predict with any accuracy. The rate and magnitude of future oil discoveries and development thereof will depend to a large extent on economic and political considerations, market demand for energy, the cost of competitive alternate energy sources, and the rate of technological improvements. The following analysis should be helpful, however, in assessing the oil industry's longer term ability to meet the staggering increase in oil demand that is expected between 1971 and 1985.

Earlier in this report U.S. and Free Foreign oil demand was projected as shown in Table XXXII for the period 1970-1985 inclusive.

Table XXXIII, which incorporates the estimated Free World proved oil reserves reported by the *Oil & Gas Journal* in its December 28, 1970, issue, reflects one approach towards demonstrating the current availability of sufficient crude reserves to meet Free World oil requirements over the next 15 years.

TABLE XXXII

FREE WORLD OIL DEMAND

	NPC Forecast (MMB/D) 1970	1985	Avg. Annual % Increase	Oil Production Required for 1971-1985 Inclusive to Meet Forecasted Demand (Billion Barrels)
United States	14.7	26.0	3.9	110.6
Free Foreign	25.4	66.0	6.6	241.1
TOTAL FREE WORLD	40.1*	92.0	5.7	351.7

* Total liquid hydrocarbon demand; differs from 37 MMB/D shown in last paragraph of p. 27, Volume One, which relates to crude oil only.

TABLE XXXIII

PROVED RESOURCES VS. PRODUCTION REQUIREMENTS
(Billions of Barrels)

	Est. Proved Oil Reserves as of 12/31/70*	Est. Oil Production Required To Meet Free World Oil Demand--1971-85	Indicated Surplus or Deficit
United States (including North Slope)	37.0	110.6	(73.6)
Free Foreign	474.4	241.1	233.3
TOTAL FREE WORLD	511.4	351.7	159.7

* *Oil & Gas Journal* (December 28, 1970).

An assessment of Free World foreign demand and supply, as shown in Table XXXIII, indicates that sufficient foreign reserves would be available to assume that worldwide demand could be satisfied through 1985. The relationship between proved Free World oil reserves as of December 31, 1970, and estimated Free World oil demand for 1971-1985 inclusive indicates that total oil requirements for this period could be covered by existing Free World proved oil reserves even if we assume there are *no* gross additions to reserves realized during the next 15 years. This is, of course, a wholly unrealistic assumption. More importantly, it reflects only part of the question. While the reported proved reserves of 511 billion barrels exceed estimated required production of 352 billion barrels for 1971-1985, the remaining reserves of 160 billion barrels would not be sufficient to sustain the estimated 1985 production of 33 billion barrels annually, as the ratio of reserves to production would then be less than 5 to 1. The above data also indicate that, without significant changes in domestic oil industry activities and/or Federal Government policies to strengthen domestic exploration/development incentives, the U.S. oil consumer will become increasingly dependent either on foreign crude supplies or on higher cost alternative energy sources or on some combination of both.

As noted previously, Table XXXIII reflects only the current Free World *proved* oil reserve situation without any allowance for additions to proved oil reserves during the next 15 years. It will, therefore, be of interest to reflect on the following recent Free World gross addition trends (see Tables XXXIV and XXXV).

TABLE XXXIV

TOTAL GROSS ADDITIONS TO PROVED OIL RESERVES*
(Billions of Barrels)

Period	U.S.†	Free Foreign	Free World
1955-1960	14.4	99.3	113.7
1960-1965	13.5	77.7	91.2
1965-1970	14.8	230.2	245.0
1955-1970	42.7	407.2	449.9

* Basis: *Oil & Gas Journal.*
† Excludes allowance for Alaskan North Slope.

TABLE XXXV

AVERAGE ANNUAL GROSS ADDITIONS TO PROVED OIL RESERVES*
(Billions of Barrels)

Period	U.S.†	Free Foreign	Free World
1955-1960	2.9	19.8	22.7
1960-1965	2.7	15.5	18.2
1965-1970	3.0	46.0	49.0
1955-1970	2.8	27.2	30.0

* Basis: *Oil & Gas Journal.*
† Excludes allowance for Alaskan North Slope.

If the exploration/development activity and experience trends of the last 15 years can be sustained for another 15 years, the oil industry can find and develop sufficient new gross additions to cover expected 1971-1985 Free World crude requirements. This is shown in Table XXXVI, which also serves to illustrate again the increasingly serious oil supply situation confronting the United States if recent domestic oil finding/development trends are not soon reversed.

The Oil Subcommittee concluded that it was reasonable to expect gross additions to Free World proved oil reserves to at least equal the gross

TABLE XXXVI

RECENT GROSS ADDITIONS TO PROVED OIL RESERVE TRENDS COMPARED TO EXPECTED OIL REQUIREMENTS (1971-1985)
(Billions of Barrels)

	Total Gross Additions to Proved Oil Reserves (1955-1970)	Total Estimated Oil Demand (1971-1985)
United States	42.7	110.6
Free Foreign	407.2	241.1
TOTAL FREE WORLD	449.9	351.7

additions achieved during the past 15 years and that more likely gross additions would approximate 500 billion barrels during the period 1971-1985. This, of course, assumes that political and economic conditions throughout the Free World will continue to provide rewarding investment opportunities. Any events that adversely affect the political or economic climate will have a negative impact on future oil finding and development.

All of the foregoing analysis rests heavily on acceptance of the *Oil & Gas Journal* proved oil reserve estimates as of December 31, 1970 (see Table XXXVII), and the NPC oil demand forecast to 1985.

The Subcommittee concluded that the oil demand forecast--and most particularly the assumptions on which the forecast is based--are sufficiently well documented in the report to afford each reviewer a sound basis for independently determining the validity of the forecast. However, it was considered essential to provide an independent reserves estimate to check the *Oil & Gas Journal* values. Thus the oil companies participating in the NPC Energy Study were asked to provide their own assessments of the *Oil & Gas Journal* proved reserve estimates. Altogether, 14 oil companies responded, including all of the U.S.-based international oil companies. Each reporting company restricted its response to comments on the general geographical area reserve estimates as reported by the *Oil & Gas Journal*, either in percent differences or billion barrel differences. Each company respondent also requested that its assessment not be directly attributed to it because of the confidential nature of the opinions involved. Finally, almost all oil company respondents indicated that their comparisons with the data published by the *Oil & Gas Journal* were based on internal estimates of "proved reserves" worldwide as measured under the API definition of "proved crude oil reserves."

A summary comparison of the NPC survey results and the *Oil & Gas Journal* proved reserve estimates is shown in Table XXXVIII.

Based on the foregoing comparison, the Oil Supply Task Group concluded that the *Oil & Gas Journal* "proved" crude oil reserve estimate is too high by about 100 billion barrels, or 25 percent. The difference centers principally in the Middle East (general) and Africa (Algeria and Libya) estimates. The likely explanation of the difference is the employment by most company respondents of internal estimates of "proved reserves" as defined by the API, while the *Oil & Gas Journal* estimate might include some reserves that should be classified as "probable" rather than "proved," based on API definitions.

TABLE XXXVII

WORLD RESERVES AND PRODUCTION--1970

COUNTRY	RESERVES		WELLS		OIL PRODUCTION			REFINING		
								Capacity (MB/D) January 1, 1971		
	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
ASIA-PACIFIC										
Afghanistan............	95,000*	5,000	16*	6	46.8*	---	---	---	---	---
Australia..............	2,000,000	12,600	386	14	170.1	210.0	10	640.0	157.3	144.1
Brunei-Malaysia.........	1,000,000	6,000	592	7	146.2	8.0	3	126.5	---	6.0
Burma..................	40,000	80	45	10	15.6	-2.5	2	26.3	5.0	---
Cambodia................	---	---	---	---	---	---	1	13.5	---	2.0
Ceylon..................	---	---	---	1	---	---	1	30.0	12.0	3.7
India...................	956,000	1,800	200	43	139.0	-8.0	10	429.3	87.7	18.8
Indonesia...............	10,000,000	3,000	2,136	29	861.2	17.0	6	251.2	106.5	15.0
Japan...................	30,000	550	1,725	15	16.3	3.2	42	3,698.8	168.1	355.8
Korea, South............	---	---	---	---	---	---	2	250.0	---	24.6
New Zealand.............	226,000*	6,500	6†	2	.06	---	1	66.0	---	21.0
Pakistan................	41,500	20,000	17	9	9.8	2.0	4	115.1	---	4.0
Philippines.............	---	---	---	1	---	---	4	205.0	27.7	24.6
Taiwan..................	20,000	800	51	8	1.7	6.2	1	118.0	10.0	8.0
Thailand................	148	---	26	1	0.3	200.0	3	962.0	34.4	14.1
TOTAL ASIA-PACIFIC	14,408,648	56,330	5,200	146	1,407.1	31.7	90	6,060.9	608.7	641.7

*Condensate.
†Four Kapuni wells now producing but at no regular rate yet; tiny Moturoa field has 2 oilers.

COUNTRY	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
EUROPE										
Austria.................	180,000	431	1,268	13	54.7	7.3	2	159.5	18.0	10.0
Belgium.................	---	---	---	---	---	---	7	704.0	59.1	82.3
Denmark.................	---	---	---	---	---	---	3	196.0	31.0	33.1
Finland.................	---	---	---	---	---	---	2	173.0	23.0	33.6
France..................	125,000	7,200	324	3	47.7	-5.7	24	2,533.8	203.5	392.8
Greece..................	---	---	---	1	---	---	3	102.0	---	15.0
Ireland.................	---	---	---	1	---	---	1	55.0	---	14.5
Italy (incl. Sicily)....	225,000	5,000	136	12	24.5	-15.5	36	3,235.3	624.4	356.3
Netherlands.............	261,000	83,000	369	7	36.5	-5.9	7	1,392.5	85.0	163.9
Norway..................	1,000,000*	3,000	(†)	4	(†)	(†)	3	202.0	16.0	20.0
Portugal................	---	---	---	---	---	---	2	84.0	26.0	11.0
Spain...................	8,500	---	21	4	3.6	---	8	846.0	10.2	124.0
Sweden..................	---	---	---	---	---	---	5	236.0	33.0	47.5
Switzerland.............	---	---	---	---	---	---	2	102.0	21.0	18.3
United Kingdom..........	1,000,000*	36,000	60	4	1.8	-1.0	21	2,392.3	206.0	350.0
West Germany............	584,000	11,900	3,065	18	147.1	-4.6	35	2,541.8	336.6	321.5
Yugoslavia..............	325,000	1,200	---	---	40.5	-23.6	6	222.0	23.1	32.9
TOTAL EUROPE	3,708,500	147,731	5,243	67	356.4	-6.7	167	15,177.2	1,715.9	2,026.7

*Preliminary estimate includes North Sea oil discoveries.
†To begin production in Spring, 1971.

COUNTRY	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
MIDDLE EAST										
Abu Dhabi...............	11,800,000	9,500	94	6	640.9	6.6	---	---	---	---
Bahrain.................	634,000	5,000	232	1	76.8	1.1	1	216.0	59.1	16.0
Dubai...................	983,000	750	11	2	77.9	---	---	---	---	---
Iran....................	70,000,000	214,000	266	17	3,753.2	14.2	5	632.8	52.0	81.5
Iraq....................	32,000,000	18,500	113	2	1,517.8	-0.6	6	102.9	14.0	8.0
Israel..................	12,900	72	32	2	93.0*	77.7	1	132.0	27.0	16.0
Jordan..................	---	---	---	1	---	---	1	15.6	1,350.0	8.7
Kuwait..................	67,100,000	38,000	741	1	2,743.8	9.1	3	504.0	---	13.6
Lebanon.................	---	---	---	---	---	---	2	54.5	---	7.6
Neutral Zone............	25,700,000	8,000	450	2	485.6	7.5	2	80.0	---	---
Oman....................	1,700,000	2,000	62	2	336.1	7.1	---	---	---	---
Qatar...................	4,300,000	8,000	69	1	353.9	0.3	1	68.0	---	---
Saudi Arabia............	128,500,000	49,500	423	5	3,437.5	19.9	2	906.0	---	47.5
South Yemen (Aden)......	---	---	---	1	---	---	1	178.0	---	10.0
Syria...................	1,200,000	750	90	8	50.0	4.1	1	59.0	20.0	3.5
Turkey..................	645,000	190	279	4	68.0	-0.9	4	290.0	23.5	30.1
TOTAL MIDDLE EAST	344,574,900	354,262	2,862	55	13,634.5	12.3	30	3,171.7	196.9	234.6

*Includes captured Sinai fields.

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COUNTRY	RESERVES Oil (MB)	RESERVES Gas (BCF)	WELLS Producing oil 7-1-70	WELLS Drilling 12-1-70	OIL PRODUCTION Estimated 1970 (MB/D)	OIL PRODUCTION % change from 1969	No. refs.	REFINING Capacity (MB/D) January 1, 1971 Crude	Cracking	Reforming
AFRICA										
Algeria	30,000,000*	141,000	775	25	984.0	275.0	2	48.3	---	13.0
Angola (incl. Cabinda)	500,000	1,000	141	4	110.0	131.6	1	14.0	---	2.0
Congo-Brazzaville	3,600	---	5	1	0.5	-37.5	1	33.0	---	3.0
Congo-Kinshasa	1,000†	---	---	1	---	---	---	---	---	---
Dahomey	1,000†	---	---	1	---	---	---	---	---	---
Egypt	4,500,000	5,000	332	9	328.5	35.9	3	175.0	5.0	15.2
Ethiopia	---	---	---	---	---	---	1	13.4	---	1.8
Gabon	700,000	7,000	100	4	106.0	7.5	1	17.2	7.9	1.5
Ghana	1,000†	---	---	2	---	---	1	28.0	---	6.5
Ivory Coast	---	---	---	---	---	---	1	19.0	---	3.0
Kenya	---	---	---	1	---	---	1	50.5	---	4.6
Liberia	---	---	---	---	---	---	1	10.0	---	2.0
Libya	29,200,000	30,000	1,083	13	3,385.0	11.0	1	9.5	---	2.2
Malagasay	---	---	---	2	---	---	1	11.9	---	2.0
Morocco	920	16	52	1	1.0	-28.5	2	35.0	4.0	7.7
Mozambique	---	---	---	1	---	---	1	47.0	---	8.5
Nigeria	9,300,000	6,000	364	18	1,000.0	93.0	1	55.0	---	4.6
Rhodesia	---	---	---	1	---	---	---	---	---	---
Senegal	---	---	---	---	---	---	1	12.0	---	2.0
Sierra Leone	---	---	---	---	---	---	1	10.0	---	---
Sudan	---	---	---	---	---	---	1	20.0	---	2.0
Tanzania	---	---	---	---	---	---	1	30.6	---	7.7
Tunisia	550,000	1,000	46	3	88.0	10.2	1	22.5	---	3.3
Union of South Africa	---	500†	---	4	---	---	5	262.9	73.5	59.4
TOTAL AFRICA	74,757,520	191,516	2,898	91	6,003.0	36.5	29	924.9	90.4	152.1

*Government estimate.
†Oil or gas discovered but not yet developed.

COUNTRY	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
WESTERN HEMISPHERE										
Argentina	4,500,000	8,800	5,400	26	391.0	15.0	14	456.2	232.0	18.9
Bahamas	---	---	---	1	---	---	1	250.0	---	---
Barbados	750*	---	---	1	---	---	1	3.0	---	---
Bolivia	225,000	5,000	171	10	13.2	-70.9	5	23.1	---	---
Brazil	850,000	6,000	1,015	28	157.6	-12.2	10	504.6	92.5	39.5
British West Indies	---	---	---	1	---	---	1	16.0	---	2.0
Chile	125,000	2,000	380	8	38.3	3.0	2	111.0	32.5	10.0
Colombia	1,675,000	2,800	2,171	5	222.0	6.7	5	137.6	76.0	---
Costa Rica	---	---	---	---	---	---	1	8.0	3.0	1.2
Cuba	14,000	---	15	12	2.5	---	3	93.0	24.0	15.0
Ecuador	750,000	5,000	708	7	4.0	-18.4	1	35.3	7.0	1.0
El Salvador	---	---	---	---	---	---	1	13.0	---	2.0
Guatemala	---	---	---	---	---	---	2	26.0	---	6.0
Honduras	500*	---	---	---	---	---	1	14.0	---	1.6
Jamaica	---	---	---	1	---	---	1	36.0	---	3.2
Mexico	3,200,000	10,000	3,127	80	427.4	5.5	6	574.2	102.0	94.2
Netherlands Antilles	---	---	---	---	---	---	2	790.0	497.0	22.0
Nicaragua	---	---	---	1	---	---	1	22.0	---	4.3
Panama	---	---	---	---	---	---	1	75.0	22.4	7.5
Paraguay	---	---	---	---	---	---	1	5.0	---	---
Peru	270,000	3,000	2,500	5	72.0	20.0	5	91.5	22.7	1.8
Puerto Rico	---	---	---	---	---	---	2	140.0	75.5	88.0
Trinidad and Tobago	575,000	3,500	3,133	6	141.0	-13.0	3	438.0	26.5	27.0
Uruguay	---	---	---	---	---	---	1	40.0	10.0	3.0
Venezuela	14,000,000	27,000	9,364	14	3,690.0	3.3	12	1,526.1	157.5	23.1
Virgin Islands	---	---	---	---	---	---	1	250.0	---	15.0
United States	37,012,640	265,000	640,760	1,065	9,506.5	3.6	262	13,293.0	8,514.0	3,065.0
Canada	10,750,000	60,451	23,675	141	1,277.5	15.4	41	1,450.0	735.0	245.0
TOTAL W. HEMISPHERE	73,947,890	398,551	692,419	1,411	15,943.0	4.2	386	20,421.6	10,540.2	3,696.0

*Oil or gas discovered but not yet developed.

COUNTRY	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
TOTAL FREE WORLD	511,397,458	1,148,390	708,622	1,770	37,344.0	10.3	702	45,757.0	13,242.0	6,752.0
COMMUNIST WORLD	100,000,000*	440,000†	---	---	7,566.0	7.4	---	---	---	---
TOTAL WORLD	611,397,458	1,588,390	---	---	44,910.0	16.7	---	---	---	---

*Including Russia 77 billion, Red China 20 billion, Hungary 1 billion, others 2 billion.
†Including Russia 426 trillion, Red China 4 trillion, Hungary 3.5 trillion, Poland 5 trillion.

TABLE XXXVIII

COMPARISON NPC SURVEY OF FREE WORLD PROVED CRUDE OIL RESERVES WITH *OIL & GAS JOURNAL* ESTIMATE
(Billions of Barrels)

	As Reported by the *Oil & Gas Journal* 12/28/70	Range of Difference Per NPC Comparison Survey (+ or -)	Percent Difference Range
Western Hemisphere			
United States	37.0	+2.0*	
Other North America	10.8	-1.0 to +3.0	
Latin America	26.1	-3.0 to -1.0	
TOTAL WESTERN HEMISPHERE	73.9	-2.0 to +4.0	-3% to +5%
Eastern Hemisphere			
Europe	3.7	-3.0 to -2.0	
Africa	74.8	-37.0 to -20.0	
Middle East	344.6	-115.0 to -70.0	
Asia-Pacific	14.4	-2.0 to 0.0	
TOTAL EASTERN HEMISPHERE	437.5	-157.0 to -92.0	-36% to -21%
TOTAL FREE WORLD	511.4	-159.0 to -88.0	-31% to -17%

*All oil companies used the API proved crude oil reserve estimate as of 12/31/70.

To check this the Oil Supply Task Group also asked the oil companies participating in the NPC Energy Study to assess the *Oil & Gas Journal* proved crude oil reserve estimate on the basis of their own estimates of "proved" plus "probable" crude oil reserve estimates. On this basis the difference in oil company estimates decreased to a range of 15 to 60 billion barrels or 3 to 12 percent lower than the *Oil & Gas Journal* estimate. The Oil Supply Task Group concluded that the *Oil & Gas Journal* estimate of Free World proved crude oil reserves was too high by about 25 billion barrels or 5 percent, based on the oil companies' concensus estimate of "proved" plus "probable" crude oil reserves as measured under the API definition of these terms.

It was a principal finding of the Oil Supply Task Group that current Free World proved oil reserves plus probable reserve additions will be sufficient to meet projected Free World oil demand to 1985 whether the *Oil & Gas Journal* estimate of proved reserves or the much lower NPC oil companies' survey concensus estimate of "proved" crude oil reserves is used. This assumes that 450 to 500 billion barrels of expected gross additions will be made to Free World proved oil reserves before 1985. This finding again presumes that economic and political conditions throughout the Free World will continue to provide rewarding investment opportunities and permit the relatively unrestricted movement of crude oil from major crude producing areas to major crude consuming areas within the Free World.

The period from 1985 to 2000 is to be addressed in the subsequent work of the Oil Supply Task Group. In that later period it is quite possible that an entirely different picture will emerge. Some measure of that possibility can be gained from the following observation. Total Free World demand in 1985 has been estimated at 92 MMB/D or 33.6 billion barrels per year. With a future finding rate of 30 billion barrels annually, consumption will exceed supply additions in the early 1980's. Should current trends continue, the ratio of crude oil reserves to production on a world basis would decline from about 38 currently to 17 in 1985. These data suggest the need for further evaluation of supply in the post-1985 period.

The Oil Supply Task Group also concluded that it was imperative that long-term Canadian and Latin American crude producing potential be evaluated for the following reasons:

- The continuing steady decline in the proved crude oil reserve position and the diminishing spare producing capacity in the lower 48 states
- The decline in Canadian proved crude oil reserves as of December 31, 1970, recently reported by the Canadian Petroleum Association
- The relatively small growth in productive capacity realized in Venezuela over the last 10 years
- The projected steady increase in U.S. oil requirements and the apparently diminishing capability of Western Hemisphere sources to meet Western Hemisphere needs.

Following are the principal findings of the Oil Supply Task Group evaluations.

1. Canada

Two years ago the Geological Reserves Committee of the Canadian Petroleum Association estimated the ultimate potential crude oil reserves for all of Canada at 121 billion barrels. Recently, the Canadian Petroleum Association reported its estimate of total proved and probable cumulative crude oil reserves found and recognized as of December 31, 1970, at 15 billion barrels. Based on these two estimates, the remaining as-yet-undiscovered crude oil potential of Canada is huge, at 106 billion barrels, or about 90 percent of the ultimate potential crude oil reserves for all of Canada.

Only a small part--less than 15 percent--of Canada's undiscovered potential oil reserves are located in the Western Canadian Sedimentary Basin, which encompasses the traditional crude producing provinces of Alberta, Saskatchewan and Manitoba. The 15-percent figure is based on the Geological Reserves Committee estimate of the ultimate potential crude oil reserves for the Western Canadian Sedimentary Basin of 45 billion barrels, less 15 billion barrels included therein for the relatively unexplored Yukon and Northwest Territories portion of the basin. This leaves 30 billion barrels of ultimate potential for Alberta, Saskatchewan and Manitoba, of which 15 billion barrels, or 50 percent, have already been found and recognized.

The relatively small remaining potential yet to be discovered and developed in Alberta, Saskatchewan and Manitoba is regarded as significant for the following reasons: First, in 1970 Canada's proved crude oil reserves, as reported by the Canadian Petroleum Association, declined for the first time since 1946. Second, the amount of oil found per well or per foot drilled in Western Canada is projected to decline during the next 15 years, and the cost of finding new oil reserves there will probably increase. This outlook essentially confirms the recently reported findings of Mr. George W. Govier, Chairman, Alberta Oil and Gas Conservation Board. Third, it is likely that most of the larger and more easily identifiable accumulations of oil have already been found in Western Canada and that the remaining estimated 15-billion-barrel potential will become increasingly difficult to find. Fourth, the proved remaining recoverable oil reserves of Western Canada probably will level off soon and begin to decline, if, in fact, they have not already done so as evidenced by the decline in proved crude oil reserves reported at the end of 1970.

Growth in Canadian proved crude oil reserves and production over the next 15 years will be highly dependent on the success of exploration in the frontier areas of the Yukon, Northwest Territories, Arctic Islands and Canadian Arctic, and Offshore. Evidence already indicates that the major focus of exploration activity in Canada has shifted from Western Canada to the frontier areas. In 1970, about 45 percent of the major Canadian producers' exploration expenditures were spent in these frontier areas. This proportion is estimated to increase to between 60 and 65 percent by 1975.

No significant oil discovery in any of the frontier areas has been announced to date. The Oil Supply Task Group assessment of the geological potential of these frontier areas suggests that the discovery of a "giant" field is imminent. The actual timing of such a discovery is, however, uncertain at best. Even if it occurs in the next 2 or 3 years, it can have little effect on Canadian proved crude oil reserve or production trends until after 1975 because of the remoteness of most of these areas to existing transportation and refining facilities.

Based on all of the foregoing data, the Oil Supply Task Group estimated conventional Canadian crude producing capacity and production as shown in Table XXXIX.

2. Latin America

Any assessment of Latin America's crude producing capacity over the next 15 years is basically related to Venezuela's current predominant position in the area.

TABLE XXXIX

ESTIMATED CANADIAN PRODUCING CAPACITY AND PRODUCTION
(MB/D)

	1970	1975	1980	1985
Producing Capacity				
Western Canada*	2,275	2,600	2,400	2,250
Frontier areas	0	0	400	1,200
TOTAL	2,275	2,600	2,800	3,450
Memo: From Tar Sands	45	65	375	1,000
Production				
Western Canada*	1,316	2,005	2,185	2,200
Frontier areas	0	0	400	1,200
TOTAL	1,316	2,005	2,585	3,400
Memo: From Tar Sands	33	65	375	1,000

* Alberta, Saskatchewan, Manitoba and British Columbia. Includes conventional crude only.

The Oil Supply Task Group's view of long-term productive capacity in Venezuela is pessimistic. First, Venezuelan production did not significantly increase in response to a sharp surge in the demand for its oil following the major Middle East/Africa supply disruptions of 1967 and 1970. Second, the Venezuelan government continues to emphasize the need to conserve its oil reserves to meet growing domestic requirements unless sizable new oil reserves are soon found and developed. Third, and particularly important, major contract concession arrangements terminate in the early 1980's. Substantial uncertainty exists today about the terms of the "service contracts" which will take the place of present concession arrangements. This uncertainty adversely affects the prospects for any significant growth in productive capacity in the short term. So long as this uncertainty continues, oil companies will view development prospects in Venezuela conservatively.

Significant increases in productive capacity by 1985 in other Latin American countries are very dependent on the success of exploration efforts now under way and anticipated future exploration activities. Although there is some reason to be optimistic about future oil developments in some of these countries, it is unlikely that results will be sufficient to offset the expected decline in Venezuelan productive capacity. Furthermore, such success as is ultimately achieved in other Latin American countries is most likely to result in improved local crude self-sufficiency, rather than increased export crude availability.

Based on the foregoing data, the Oil Supply Task Group estimated Latin American crude and condensate producing capacity and production as shown in Table XL.

3. *Western Hemisphere Liquid Hydrocarbon Supply--Oil Consumption Balance*

Table XLI presents a Western Hemisphere Liquid Hydrocarbon Supply--Oil Consumption Balance to 1985, which incorporates the forecasts of the Oil Demand and Supply Task Groups. Any interpretation of this balance must

TABLE XL

ESTIMATED LATIN AMERICAN PRODUCING CAPACITY AND PRODUCTION
(MB/D)

	1970	1975	1980	1985
Producing Capacity				
Conventional Crude and Condensate	5,350	5,825	6,700	6,200
Synthetic*	---	---	250	700
TOTAL	5,350	5,825	6,950	6,900
Production				
Conventional Crude and Condensate	5,200	5,700	6,600	6,150
Synthetic*	---	---	250	700
TOTAL	5,200	5,700	6,850	6,850

* Orinoco Tar Belt.

TABLE XLI

WESTERN HEMISPHERE LIQUID HYDROCARBON SUPPLY--OIL CONSUMPTION BALANCE (1960-1985)
(MB/D)

	Actual			Estimated			
Domestic Oil Consumption	1960	1965	1970	1975	1980	1985	
United States	9,807	11,523	14,719	18,346	22,329	25,976	
Canada	854	1,148	1,485	1,897	2,290	2,750	NPC Oil Demand Task Group estimates
North American Atlantic Islands	1	2	3	4	5	6	
Latin America	1,708	2,068	2,815	3,663	4,530	5,510	
Total Western Hemisphere Oil Consumption	12,370	14,741	19,022	23,910	29,154	34,242	
Crude and Condensate Production							
United States--Lower 48 and South Alaska	7,035	7,804	9,631	8,930	8,430	8,110	
--North Slope	--	--	--	600	2,000	2,000	
Subtotal	7,035	7,804	9,631	9,530	10,430	10,110	
Canada--Western Canada	518	799	1,316	2,005	2,185	2,200	NPC Oil Supply Task Group estimates
--New Frontier Areas	--	--	--	--	400	1,200	
Subtotal	518	799	1,316	2,005	2,585	3,400	
Latin America	3,739	4,615	5,200	5,700	6,600	6,150	
Total Western Hemisphere Crude & Condensate Production	11,292	13,218	16,147	17,235	19,615	19,660	
NGL Production							
United States	930	1,210	1,696	1,550	1,330	970	
Canada	26	124	218	280	370	400	
Latin America	50	96	149	243	360	320	NPC Oil/Gas Supply Task Group estimate
Total Western Hemisphere NGL Production	1,006	1,430	2,063	2,073	2,060	1,690	
Total Conventional Liquid Hydrocarbon Production							
United States	7,965	9,014	11,327	11,080	11,760	11,080	
Canada	544	923	1,534	2,285	2,955	3,800	Calculated: Crude and Condensate plus NGL production
Latin America	3,789	4,711	5,349	5,943	6,960	6,470	
Total Western Hemisphere	12,298	14,648	18,210	19,308	21,675	21,350	
Conventional Liquid Hydrocarbon Production Available for Export or (Imports Required)							
United States	(1,842)	(2,509)	(3,392)	(7,266)	(10,569)	(14,896)	
Canada	(310)	(225)	49	388	665	1,050	Calculated: Difference between Domestic Oil Consumption and total conventional liquid hydrocarbon production
North American Atlantic Islands	(1)	(2)	(3)	(4)	(5)	(6)	
Latin America	2,081	2,643	2,534	2,280	2,430	960	
Total Western Hemisphere	(72)	(93)	(812)	(4,602)	(7,479)	(12,892)	
Less: Synthetic Liquid Production(Potential)							
United States--Oil Shale	--	--	--	--	100	400	NPC Oil Shale Task Grp. est.
--Coal	--	--	--	--	50	200	NPC Coal Task Group estimate (accelerated basis)
Subtotal	--	--	--	--	150	600	
Canada--Tar Sand	--	--	33	65	375	1,000	NPC Tar Sands Task Group est.
Latin America--Synthetic	--	--	--	--	250	700	NPC Oil Supply Task Group est.
Total Western Hemisphere Synthetic Production	--	--	33	65	775	2,300	
Total Liquid Hydrocarbon Production (Conventional Plus Synthetic) Available for Export or (Imports Required)							
United States	(1,842)	(2,509)	(3,392)	(7,266)	(10,419)	(14,296)	
Canada	(310)	(225)	82	453	1,040	2,050	
North American Atlantic Islands	(1)	(2)	(3)	(4)	(5)	(6)	Calculated
Latin America	2,081	2,643	2,534	2,280	2,680	1,660	
Total Western Hemisphere	(72)	(93)	(779)	(4,537)	(6,704)	(10,592)	

recognize that the liquid hydrocarbon supply projections are conservatively biased, as they project recent finding and development trends that are generally unfavorable; current price levels that are most likely to change upward, and existing government policies that are also likely to change, hopefully with constructive and positive impact on oil industry incentives.

Despite its conservatism, the Balance implies and reflects a steadily increasing reliance on Eastern Hemisphere liquid hydrocarbon supplies to meet rapidly growing Western Hemisphere requirements. This is particularly true in the case of the United States, but applies as well to Canada and Latin America. A most particularly significant implication of the Balance is that it is a very doubtful posture--if not a wholly unrealistic one--to place too much long-term dependence on Canadian or Latin American crude/condensate reserves to meet the projected growing U.S. oil deficit. In fact, the Oil Supply Task Group concludes that the Canadian and Venezuelan governments will not permit dedication of their petroleum reserves to U.S. markets on a long-term basis. The task group notes with concern the already building sentiment in both Canada and Venezuela against any such long-term commitments too far in advance of an ability to reliably predict the consequences on their economies or before detailed assessments of long-term domestic requirements and supply capabilities are completed by the then responsible governments of Canada and Venezuela.

All of the foregoing analysis of foreign supply capability was developed prior to the OPEC settlements of 1971. The impact of these settlements will be considered in the future work of the Oil Supply Task Group.

Chapter Four

OIL LOGISTICS TASK GROUP REPORT

ABSTRACT

The principal logistical assumption underlying the initial appraisal is that new supply requirements not met by domestic production of crude oil and natural gas liquids will be imported. The supply/demand balances for the period 1971-1985 indicate the following outlook:

- Total supply necessary to meet projected U.S. demands will increase from 14.7 MMB/D in 1970 to 25.6 MMB/D in 1985.
- Domestic production of crude oil and natural gas liquids during the 1971-1985 period will remain on the order of 11+ MMB/D, under the assumptions of the initial appraisal. Delivery of crude oil from the Alaskan North Slope beginning in 1975 will offset production declines in the lower 48 states.
- Imports of crude oil and refined products would have to rise sharply to cover the growing gap between total requirements and domestic production. It has been assumed that from the national security and balance of payments viewpoints, it would be preferable to import crude oil rather than refined petroleum products.
- At least 10 MMB/D of net new refinery capacity will need to be constructed in the United States during the next 15 years. The rate of installing such capacity would have to be 2.5 times that of the 1960's. The question of where to locate this new refinery capacity needs to be resolved.
- Economy of scale considerations would dictate the use of very large crude carriers in the 300,000 to 400,000 DWT range to transport foreign oil to U.S. shores. There are at the present time no developed ports in the United States capable of handling vessels of this size.
- The capital costs for new refineries and external logistical facilities necessary to meet oil requirements in the United States total more than $40 billion over the next 15 years.

Recognizing the limited utility of the initial appraisal, the Oil Logistics Task Group did not attempt to develop detailed supply/demand balances for each individual PAD District. Inter-district movements and import flows by districts will be postulated in future work along the lines of the examples shown in this volume for PAD District I and PAD District V.

SUMMARY REPORT OF OIL LOGISTICS TASK GROUP

For purposes of the initial appraisal, the Oil Logistics Task Group was charged with accomplishing the following:

- Calculating supply/demand balances for the years 1970, 1975, 1980 and 1985, using demand data provided by the Oil Demand

Task Group, domestic crude oil production estimates generated by the Oil Supply Task Group, and domestic condensate and natural gas liquids production data developed by the Gas Supply Task Group.

- Assessing the broad logistical implications of stated assumptions underlying the initial appraisal.
- Calculating capital requirements (in 1970 dollars) for petroleum refining and logistics systems needed to meet future demands as specified.

LOGISTICAL ASSUMPTIONS

The principal logistical assumption underlying the initial appraisal is that supply requirements not met by domestic production of conventional or synthetic crude oil and natural gas liquids will be imported.

It is further assumed that Alaskan North Slope crude oil will be made available to the lower 48 states, beginning at the initial rate of 600 MB/D in 1975 and growing to a capacity level of approximately 2 MMB/D by 1980. Although Alaska is noncontiguous to the continental United States, the output of Alaskan oil is included as domestic production.

Overland imports of Canadian crude oil (conventional and synthetic) are projected to increase about 8 percent per annum between 1971 and 1985. This is based on the assumption that recoverable reserves on the order of 8 to 10 billion barrels will be developed in Northern Canada and in the Canadian Atlantic offshore area.

U.S. PETROLEUM SUPPLY AND DEMAND

Total U.S. petroleum supply and demand patterns at 5-year intervals for the period 1960-1985 are arrayed on Table XLII.

The general observation may be made that the United States appears to have passed through a transition from a position of petroleum surplus in the past decade to one of growing supply deficiency. Except during World War II, the United States had maintained sufficient reserve petroleum productive capacity to meet normal growth in internal demands as well as emergency requirements of its allies. In 1960, for example, a surplus position was indicated in the sense that spare crude oil and natural gas liquids productive capacity exceeded total imports of crude oil and refined products. On this basis, the United States became oil supply deficient in 1967, and the shortfall has deepened since that time. In 1970, total imports amounted to 3.4 MMB/D while sustainable excess productive capacity from existing wells was something less than 1.5 MMB/D.

Between 1960 and 1970, U.S. domestic and export demand for liquid petroleum increased 5 MMB/D, or at a rate of 500 MB/D and 4.1 percent per annum. Two-thirds of the additional supply required for expanded demand was met by domestic production of crude oil and natural gas liquids, while the remaining one-third was imported.

Although federal oil import controls remained in effect during the 1960's, Canadian overland imports of crude oil and refined products were permitted to rise substantially, and controls on residual fuel oil imports into the U.S. East Coast were progressively relaxed and virtually abandoned

TABLE XLII

PETROLEUM DEMAND AND SUPPLY
TOTAL UNITED STATES--INITIAL APPRAISAL
(MB/D)

	Actual			Estimated		
Item	1960	1965	1970	1975	1980	1985
Domestic Demand	9,807	11,523	14,728	18,346*	22,329*	25,976*
Exports	202	187	258	235	220	210
Total Demand	10,009	11,710	14,986	18,581*	22,549*	26,186*
Processing Gain, etc.†	- 146	- 220	- 343	- 420	- 500	- 600
Stock Change, All Oils	- 83	- 8	+ 103	+ 9	+ 11	+ 14
Required New Supply	9,780	11,482	14,746	18,170	22,060	25,600
U.S. Production:						
Crude and Condensate:						
Lower 48‡	7,035	7,804	9,631	8,930	8,430	8,110
Alaskan North Slope	---	---	---	600	2,000	2,000
Subtotal	7,035	7,804	9,631	9,530	10,430	10,110
Natural Gas Liquids, etc.§	930	1,210	1,697	1,550	1,330	970
Syncrude from Oil Shale	---	---	---	---	---	100
Total Production	7,965	9,014	11,328	11,080	11,760	11,180
Imports:						
Crude Oil	1,015	1,238	1,324	4,090	6,550	10,220
Residual Fuel Oil	637	946	1,528	2,200*	2,800*	3,100*
Other Products	163	284	566	800	950	1,100
Total Imports	1,815	2,468	3,418	7,090*	10,300*	14,420*
Total Canadian Overland	120	329	766	950	1,300	1,900
Total Waterborne	1,695	2,139	2,652	6,140*	9,000*	12,520*
Imports as % of Required Supply	18.5	21.5	23.2	39.0*	46.7*	56.3*
Crude Runs to Stills	8,067	9,043	10,870	13,600	16,950	20,400

* Excludes adjustments to demand and supply later made by the Coordinating Subcommittee (see p. *xxiv* of Extract from Volume One included in this Volume Two).
† Includes unaccounted-for crude.
‡ Includes Southern Alaska.
§ Includes other hydrocarbons and hydrogen refinery input.

by 1966. As a result, Canadian overland crude and products and overseas residual fuel oil accounted for practically all of the net increase in U.S. oil imports during the past decade. From 1960 to 1970, total oil imports increased from 1.8 to 3.4 MMB/D, a gain of 1.6 MMB/D or 88 percent. Canadian overland imports increased 0.6 MMB/D, while waterborne imports rose almost 1 MMB/D. During the decade of the 1960's, essentially all of the increase in waterborne imports was landed on the U.S. East Coast.

In addition to the deficiency of total domestic petroleum raw materials, the United States has for some time been deficient in refining capacity required to produce desired products for domestic consumption. The provisions of the Mandatory Oil Import Program that effectively exempt heavy fuel oil imports into PAD District I, coupled with refinery economics and the availability of crude cracking technology, have concentrated that deficiency in a single product for a single area: residual fuel oil on the Eastern Seaboard.

The supply/demand balances beyond 1970, based on the assumptions specified for the initial appraisal, indicate growing demand for products and relatively constant total domestic production of crude oil and natural gas liquids. The essentially flat domestic production rate of 11+ MMB/D consists of a production plateau in the lower 48 states during the next several years followed by progressive declines, offset by Alaskan North Slope output beginning in 1975. Under these conditions, sharply increasing levels of imports will be needed to meet the balance of supply requirements, beginning sometime before 1975. The need for rapidly expanding oil imports is already evident on the U.S. West Coast, where demand continues to increase but where domestic production reached a peak in 1970 and is expected to decline in subsequent years. As a result, PAD District V dependence on oil imports will grow from 484 MB/D in 1970 to more than 1 MMB/D prior to 1975, the earliest that Alaskan North Slope oil could be brought into West Coast markets.

Total demand for all oils in the United States has been projected to grow from 15 MMB/D in 1970 to 26 MMB/D in 1985.* This represents an annual average gain of almost 750 MB/D, or 3.8 percent per annum over the 15-year period. Even in the shorter term between now and 1975, demand is expected to increase at an average rate of 720 MB/D per year, compared with 650 MB/D per annum in the previous 5 years.

Given the levels of total demand and domestic production postulated for the initial appraisal, total oil imports into the United States would have to increase by 3.7 MMB/D or more than 100 percent between 1970 and 1975. The level of imports would increase substantially thereafter, reaching 10.3 MMB/D by 1980 and 14.4 MMB/D by 1985. Since overland movements from Canada are likely to be restricted in the short term by limits on Canadian producibility and crude pipeline capacity, the bulk of supplementary oil supplies would have to be in the form of offshore imports.

Total offshore imports during the 1960's rose at a rate of about 100 MB/D in each year. After allowing for continuing increases in Canadian overland imports and the delivery of 2 MMB/D of Alaskan North Slope oil to the lower 48 states, offshore imports for the 1971-1985 period would need to increase over 650 MB/D per year, or 6.5 times the rate of the 1960's. This order of magnitude would also apply in the short term, with waterborne import requirements increasing from 2.6 MMB/D in 1970 to 6.1 MMB/D in 1975, an increase of 3.5 MMB/D over the 5-year period, or an average of 700 MB/D per year.*

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*Excluding adjustments later made by the Coordinating Subcommittee to offset indicated shortfalls in supply of other fuels (see Extract, *supra*, p. *xxiv*).

The initial appraisal assumes static government policies and arbitrary values for economic parameters. Total demand for petroleum products is expected to continue to grow at close to the historic rate. At the same time, production of crude and condensate in the lower 48 states is expected to increase only moderately in the next few years, then decline. This will require substantial increases in import levels beginning almost immediately. Even if national policies to stimulate domestic production of conventional or synthetic hydrocarbons were implemented today, the lead time necessary to develop additional productive capacity would be measured in terms of 3 to 5 years. Thus it appears that in the short term at least, the only alternative available to meet the projected levels of demand is to increase imports sufficiently to cover the balance of requirements not satisfied by domestic production of crude oil and natural gas liquids.

REGIONAL SUPPLY/DEMAND PATTERNS

For purposes of petroleum supply/demand analysis, the United States is divided into five PAD Districts.

As a generalization, District I (East Coast), District II (Mid-Continent) and District V (West Coast) generate demand levels in excess of regional production of crude oil and natural gas liquids. District III (Southwest) and District IV (Rocky Mountains) have petroleum output potential in excess of local requirements. This is illustrated in the following table (XLIII) summarizing the 1970 status.

TABLE XLIII

PETROLEUM SUPPLY/DEMAND SITUATION--ALL OILS--1970
(MB/D)

	PAD Districts					
Item	I	II	III	IV	V	U.S.
Domestic and Export Demand	5,966	4,037	2,537	376	2,070	14,986
Domestic Production	57	1,433	7,812	708	1,318	11,328
Shipments to Other Districts	120	223	5,580	441	24	6,388
Receipts from Other Districts	3,602	2,440	105	49	192	6,388
TOTAL IMPORTS	2,447	370	61	56	484	3,418

Since the initial appraisal assumes that liquid petroleum requirements not covered by domestic production would be imported, growing regional petroleum needs could be met by many combinations of imports and inter-district receipts. For this reason, optimum overall regional supply/demand balances for future years cannot be resolved until various supply alternatives are examined in terms of physical capability and relative costs. For purposes of illustration, however, the petroleum situation in District I and District V is outlined briefly in the following section. Much additional analysis will be required to determine future logistical patterns in the other districts; this will be considered in the future work of the Oil Logistics Task Group.

1. *The Petroleum Situation in PAD District I*

a. General

Except for nominal production of crude oil and natural gas liquids in the Appalachians and in Florida, all petroleum requirements in PAD District I are met from outside sources. Required supply for District I in 1970 amounted to 6.0 MMB/D or 40 percent of the national total. Approximately 3.6 MMB/D of supply represented inter-district receipts of crude and products, principally from District III. Except for 57 MB/D of local crude and natural gas liquids production, the balance of supply, some 2.4 MMB/D, was imported (see Table XLIV).

TABLE XLIV

PETROLEUM DEMAND AND SUPPLY--PAD DISTRICT I
INITIAL APPRAISAL
(MB/D)

Item	Actual 1960	Actual 1965	Actual 1970	Estimated 1975	Estimated 1980	Estimated 1985
Domestic Demand, All Oils	3,720	4,521	5,855	7,475	9,007	10,287
Exports	22	25	21	20	15	10
Shipments to Other Districts	78	90	120	150	180	210
TOTAL DEMAND	3,820	4,636	5,996	7,645	9,202	10,507
Less: Processing Gain, etc.*	-	36	46	55	65	75
Stock Change, All Oils	-21	-30	+66	-	+ 3	+ 3
Required Supply	3,799	4,570	6,016	7,590	9,140	10,435
U.S. Production						
Crude and Condensate	29	32	32	30	30	30
Natural Gas Liquids, etc.†	25	29	24	25	25	25
TOTAL PRODUCTION	54	61	56	55	55	55
Receipts from Other Districts:‡						
Crude Oil	520	454	681	-	-	-
Residual Fuel Oil	164	104	78	-	-	-
Refined Products (Ex-Resid)	1,689	2,167	2,754	-	-	-
TOTAL	2,373	2,725	3,513	-	-	-
Imports:‡						
Crude Oil	667	708	579	-	-	-
Residual Fuel Oil	579	873	1,471	-	-	-
Other Products	126	203	397	-	-	-
TOTAL IMPORTS	1,372	1,784	2,447	-	-	-
Crude Runs to Stills‡	1,217	1,200	1,291	-	-	-

* Includes unaccounted-for crude.

† Includes other hydrocarbons and hydrogen refinery input.

‡ Projections for PAD District I cannot be made without developing balances for PAD Districts II, III and IV. Such balances were deferred until Phase II of the study.

During the past 5 years, requirements supplied from outside District I increased 1,451 MB/D or 5.7 percent per annum. Slightly more than half of the increased requirement, or 788 MB/D, came from expanded inter-district receipts, while the remaining 663 MB/D consisted of additional imports, principally residual fuel oil. Due to international disruptions, crude imports into District I declined in 1970, but were offset by increased shipments of crude from District III.

The level of crude runs in District I has held narrowly in the range of 1.2 to 1.3 MMB/D for more than a decade, and no new refinery capacity is currently in the construction stage. District I refinery output represented only 21 percent of required supply in 1970, down from 26 percent 5 years earlier.

b. The Supply/Demand Outlook, 1971-1985

Required supply necessary to meet District I demands is expected to increase 295 MB/D a year or 3.7 percent per annum between 1970 and 1985. Unless new oil is found on the East Coast or synthetic liquids from Appalachian coal are produced, all of the required supply will have to come from outside sources. The opportunity to increase inter-district receipts of crude oil or products will depend largely on the availability of domestic crude and/or products originating on the Gulf Coast. This in turn will be dependent on the outlook for domestic crude production east of California, refinery and deepwater terminal capacity on the Gulf Coast, and the prospects for North American crude supply to upper Midwest refineries. To the extent that domestic crude production and overland imports fail to meet total liquid petroleum requirements in Districts I-V, growing waterborne imports of crude oil and products would be needed.

c. Supply Alternatives

Assuming that domestic crude oil and natural gas liquids will be in sufficiently limited supply to cause a substantial increase in imports, consideration needs to be given to the question of imports of crude oil versus refined products. The decontrol of residual fuel oil imports in 1966 resulted in a greater than 90-percent dependence on imported residual in meeting District I requirements. This has led to misgivings in at least some quarters about having such a high degree of reliance on imported oil.

On the other hand, adoption of a conscious national policy of importing and processing crude oil in domestic refineries in lieu of product imports would imply that sufficient domestic refinery capacity would be made available to meet anticipated needs.

The last new refineries built on the U.S. East Coast were completed in 1957 (Yorktown and Delaware City) prior to the imposition of mandatory import controls in 1959. No substantial net additions to crude throughput capacity in existing plants have been made in more than a decade. This trend will need to be changed materially.

2. The Petroleum Situation in PAD District V

a. General

District V has been oil supply deficient for many years. The difference between total requirements and local production has been made up by receipts from other districts and imports of crude oil and refined products. Production of liquid hydrocarbons in PAD District V has been rising slowly during the past decade, reaching an all-time high in 1970. Increases in domestic production have generally matched growing supply requirements resulting in little overall change in the level of imports and inter-district receipts over the past 5 years (see Table XLV).

TABLE XLV

PETROLEUM DEMAND AND SUPPLY--PAD DISTRICT V
INITIAL APPRAISAL
(MB/D)

Item	Actual			Estimated		
	1960	1965	1970	1975	1980	1985
Domestic Demand, All Oils	1,303	1,562	1,955	2,439	3,085	3,711
Exports	86	72	116	111	108	103
Shipments to Other Districts	39	24	24	75*	535†	25
TOTAL DEMAND	1,428	1,658	2,095	2,625	3,728	3,839
Less: Processing Gain, etc.‡	-	24	50	50	60	70
Stock Change, All Oils	-37	+38	-50	+5	+2	+1
Required Supply	1,391	1,672	1,995	2,580	3,670	3,770
U.S. Production						
Crude Oil: Lower 48§	836	899	1,252	1,165	1,100	935
Alaska N. Slope	-	-	-	600	2,000	2,000
TOTAL CRUDE	836	899	1,252	1,765	3,100	2,935
Natural Gas Liquids, etc.‖	77	65	66	60	50	40
TOTAL PRODUCTION	953	964	1,318	1,825	3,150	2,975
Receipts from other Districts	160	220	193	170	170	170
Imports:						
Crude Oil	276	404	380	470	230	500
Residual Fuel Oil	19	29	15	20	20	20
Other Products	23	55	89	95	100	105
TOTAL IMPORTS	318	488	484	585	350	625
Crude Imports--Canadian Overland	49	142	220	220	100	100
Crude Imports--Waterborne	227	262	160	250	130	400
Crude Runs to Stills	1,166	1,362	1,676	2,200	2,800	3,400

* Includes 50 MB/D North Slope crude from Valdez to District I via Panama Canal.

† Includes approximately 500 MB/D of North Slope crude to Districts I-IV by transportation means not yet determined.

‡ Includes unaccounted-for crude.

§ Includes Southern Alaska.

‖ Includes other hydrocarbons and hydrogen refinery input.

b. The Supply/Demand Outlook, 1971-1985

Requirements for liquid petroleum in District V are expected to increase 118 MB/D a year or 4.33 percent per annum between 1970 and 1985. But domestic production of crude oil and natural gas liquids on the West Coast and in Southern Alaska peaked out in 1970. As California and Southern Alaskan production continues to decline, the quantity of additional supply needed to meet West Coast requirements will increase progressively from 0.7 MMB/D in 1970 to about 2.0 MMB/D by 1980 and 2.8 MMB/D by 1985.

c. Supply Alternatives

In order to cover the growing deficiency in District V petroleum supplies at the projected demand levels, three supply alternatives may be considered:

- Increasing inter-district receipts of crude and products
- Increasing domestic production of liquid hydrocarbons
- Increasing imports of crude and products.

Since the petroleum supply/demand situation in Districts I-IV indicates a growing supply deficit in future years, the opportunity to increase inter-district receipts of crude and products into District V during the decade of the 1970's is not too promising. When and if synthetic hydrocarbon liquids from shale, coal or tar sands in District IV become economically viable, pipeline shipments to District V would come under consideration, although it seems probable that such oils would be used to meet demands east of California. For initial planning purposes, the opportunity to increase inter-district receipts may be ruled out.

The remaining alternatives involve increasing domestic production or raising the level of imports. In the short term, imports must be increased enough to cover growing total requirements as well as declines in domestic production. The availability of North Slope Alaska crude oil in West Coast refining centers will initially displace oil supplies originating outside District V, but in time the ultimate throughput capacity of the Alyeska Pipeline can be fully absorbed in West Coast markets.

d. The Alyeska Pipeline System

For planning purposes, it is assumed that Prudhoe Bay crude oil will become available in 1975 at an initial rate of 600 MB/D. Disposition from the Port of Valdez includes 50 MB/D to District I via the Panama Canal and 550 MB/D to West Coast refining centers. No provision is made for exporting North Slope crude oil to Japan or to the Virgin Islands. If 550 MB/D of North Slope oil become available to the West Coast as indicated, the 1975 level of total imports would drop to 585 MB/D compared with approximately 1 MMB/D in 1974. Thereafter, the level of imports would depend on the rate at which Prudhoe Bay oil is delivered to West Coast markets. A delivery rate of 1.5 to 1.6 MMB/D in 1980 could be fully absorbed on the West Coast, and the design capacity of 2 MMB/D could be accommodated between 1980 and 1985 without exportation or increased shipments to Districts I-IV. At these delivery rates, total imports into District V would remain near present levels. If all imports into District V were to be excluded, disposition of Prudhoe crude could be increased 500 to 600 MB/D, thereby attaining capacity delivery of the pipeline system by 1980.

If crude oil production potential on the Alaskan North Slope is fairly consistent with the Alyeska Pipeline ultimate capacity of 2 MMB/D, all the output could be absorbed on the West Coast within 5 to 10 years from initial start-up of the pipeline. At 2 MMB/D maximum production, the amount of oil available for shipment to Districts I-IV would not be sufficient to justify a pipeline link from the West Coast into District II.

FACILITIES REQUIREMENTS

1. *Tank Ships and Deepwater Terminals*

The prospect of having to increase waterborne imports into the United States at 6 to 7 times the rate experienced in the past decade adds a completely new dimension to U.S. external petroleum logistics, particularly with respect to tank ships and port facilities to accommodate them.

The optimal-size tanker in international petroleum trade during the 1971-1985 period may range from 300,000 to 400,000 DWT in long-haul trades, and 70,000 to 120,000 DWT in short-haul and coastal service. At the end of 1970, there were more than 150 tankers and combined carriers above 200,000 DWT in service, while more than 250 vessels above 200,000 DWT were on order or under construction. For general crude oil movements, a new popular-size range is 250,000 to 300,000 DWT, and there are now two tankers of 477,000 DWT on order. Tank ships over 300,000 DWT are designed to operate on specified routes, but the flexibility normally required by tank ship operators tends to restrict the deadweight tonnage to the draft limitations of existing channels and harbors. Accordingly, tank ships in short-haul and U.S. coastal service today are limited to the 70,000- to 120,000-DWT range.

While most of the increase in U.S. waterborne imports during the 1960's originated in Latin America, the prospect of increasing export crude oil availability from that area in the future is not too promising. Accordingly, most of the increase in U.S. oil import requirements will have to originate in the Eastern Hemisphere. U.S. *West Coast* crude oil imports will originate primarily in the Persian Gulf and Indonesia. The *East* or *Gulf Coast* oil import requirements could originate in the Persian Gulf, as well as North and West Africa. In each case, very large crude carriers in the 300,000- to 400,000-DWT range could be used to transport crude oil in these trades.

Vessels of 300,000 DWT and over draw a minimum of 72 feet of water when laden, but there are no ports in the United States presently capable of handling vessels of this size. Large-scale deepwater terminals to service East, Gulf and West Coast oil import requirements would be necessary.

2. *Refineries*

Except for residual fuel oil and uncontrolled products such as bonded aircraft and vessel bunker fuels, it is assumed that national security considerations would dictate that most of the increased level of imports would be crude oil. To permit increased imports in the form of finished petroleum products would be tantamount to exporting refining capacity, a step which could be considered inimical to the national interest.

If expanded nonresidual imports are basically in the form of crude oil, total crude runs in the United States would need to exceed 20 MMB/D by 1985, compared with 10.9 MMB/D in 1970. At a 95-percent operating ratio, this would require the construction of 10 MMB/D of refinery crude throughput capacity in the United States during the next 15 years. By way of contrast, net additions to operable crude capacity during the last 10 years amounted to 2.6 MMB/D. On an annual average basis, the rate of installing new refinery capacity in the United States during the next 15 years would have to be 2.5 times the rate of the 1960's.

In addition, refinery capacity would have to be added somewhere in the Free World to meet the added requirements for residual fuel oil imports to the United States of 1.5 to 2 MMB/D by 1985. This could result in the need for up to 5 MMB/D or total refining capacity, depending on characteristics of the crude, the fuel oil yield and the weight percent sulfur of the fuel oil output. Present U.S. policy would effectively cause most of this capacity to be built offshore.

The question of site selection for refineries in the United States is likely to cause severe problems in the future. On the U.S. East Coast, for example, essentially no net new refinery capacity has been added since 1957, when two new refineries were completed. District I crude runs represented 32 percent of required total supply in 1960, but only 21.1 percent in 1970. Meanwhile, product demand in District I (excluding residual fuel oil which is largely imported) accounts for about one-third of national demand for light products. Given a situation in which product demand (excluding residual fuel oil) in District I grows 3 MMB/D over the next 15 years, additions to crude throughput capacity on the East Coast should amount to more than 200 MB/D each year to meet balanced requirements for refinery capacity. The alternatives to siting refinery capacity on the East Coast are the U.S. Gulf Coast and nearby foreign areas. In any event, the required refinery capacity would have to be accessible to waterborne crude imports, and this in turn would require deepwater terminals to accommodate very large tankers.

CAPITAL REQUIREMENTS

1. Tank Ships and Deepwater Terminals

A fleet of 367 foreign-flag tankers of 250,000 DWT each has been estimated as the requirement to accommodate incremental waterborne import needs for the total United States during the next 15 years. It is convenient to use a 250,000-DWT tank ship as an average because it involves a known capital cost and because it represents a compromise between the 300,000- to 400,000-DWT vessels used in the long-haul service and the smaller, 70,000- to 120,000-DWT tankers that would be needed to distribute crude and/or products from the deepwater terminal facility to onshore refining centers or water terminals. A 250,000-DWT tanker in shuttle service from the Persian Gulf to the U.S. East Coast via the Cape of Good Hope would have a delivery capability of 26,500 B/D. Approximately the same volume per vessel would apply to movements from the Persian Gulf to the U.S. West Coast.

At $37 million per vessel (the current price quoted for 1975 delivery), the capital requirement for foreign-flag tankers to meet U.S. oil import levels during the period 1971-1985 would amount to $13.5 billion. In addition, the required capital investment for a minimum of three large-scale deepwater transfer terminals--one for East Coast, one for Gulf Coast and one for the West Coast--would be on the order of $1 billion.

2. Refineries

Construction of 10 MMB/D of refinery crude throughput capacity in the United States during the next 15 years would require capital expenditures estimated at $18 billion (1970 dollars) over the period.

Refinery cost studies indicate that the capital investment required for a complete grass-roots refinery of 200-MB/D capacity on the East Coast amounts to $346 million, or $1,730 per daily barrel of crude charge. A 100-MB/D add-on to an existing refinery of at least equal capacity is estimated to cost $1,800 per daily barrel. In both situations, the refinery facilities are designed to process crudes with sulfur contents up to 2.5 percent (by weight). Refinery output includes a 51-percent yield of a 94 research octane clear gasoline pool, 26-percent yield of 0.2-percent sulfur distillate heating oil and a 17-percent yield of 1-percent sulfur residual fuel oil. Also included is recovery of 580 tons/day of elemental sulfur. The refinery construction costs indicated in these studies normally are considered accurate in the range of -10 percent to +20 percent.

The replacement of obsolescent refinery capacity would add another $2 billion or more to the capital requirement. Thus, the total capital requirement for refineries could exceed $20 billion over the period 1971-1985. In contrast, capital spending for refineries in the United States during the previous 15-year period (1956-1970) amounted to $8.9 billion, according to data provided by Chase Manhattan Bank.

The up-to-5 MMB/D of additional foreign refinery capacity needed to supply heavy fuel oil could, if built by U.S. interests, add another $5 billion to $8 billion over the next 15 years, at least half of which could be considered dedicated to meeting U.S. needs.

3. *North Slope Transportation Systems*

The estimated initial investment in a trans-Alaskan pipeline system from Prudhoe Bay to Valdez, Alaska, and on to the West Coast ports is expected to be on the order of $3 billion, measured in 1970 dollars. This includes the pipeline, water terminals in Alaska and California, and coastal-size tankers to move oil from the Valdez terminal to discharge ports in Puget Sound, Long Beach and perhaps San Francisco. As an alternate, a trans-Canadian pipeline from Prudhoe Bay to Chicago might require an investment of $4 billion or more. These estimates were not developed independently by the task group, but were obtained from company representatives familiar with the North Slope situation.

4. *Capital Summary*

The total indicated capital requirements for refineries and external logistical facilities necessary to meet oil requirements in the United States add up to $40 to $43 billion over the period 1971-1985. This is summarized in Table XLVI.

TABLE XLVI

OIL LOGISTICS--ESTIMATED CAPITAL REQUIREMENTS
(1971-1985)

	$ Billion
Tankers	13.5
Terminals in U.S.	1.0
Refineries in U.S.	20.0
Refineries Overseas (U.S. Capital)	2.5 to 5.0
Alaskan Pipelines and Facilities	3.0 to 4.0
TOTAL	40.0 to 43.5

There is no way to determine precisely how much of this would be U.S. capital. It seems safe to assume, however, that at least that portion physically located within the United States would likely be met with U.S. funds. This could total a minimum of $24 billion (see Table XLVI), not including capital investment in internal pipelines and expanded distribution systems in the contiguous United States necessary to meet progressively higher demand levels. No assessment has been made of the capital call that might be placed on U.S. companies for foreign investment in producing operations or in logistical facilities to meet growing demand for petroleum in foreign countries.

It may be concluded from the conditions imposed by the initial appraisal that total capital requirements and consequently unit costs for petroleum products in the United States are likely to rise substantially over the next 15 years.

Chapter Five

Oil Task Group

Oil and Gas Capital Requirements

JOINT OIL AND GAS CAPITAL REQUIREMENTS TASK GROUP

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JOINT OIL AND GAS CAPITAL REQUIREMENTS TASK GROUP REPORT

ABSTRACT

The annual capital requirements of the U.S. oil and gas producing industry are estimated to rise from $4.8 billion in 1970 to $7.2 billion in 1985 (excluding Alaskan North Slope). The ability of the industry to provide these sums of money hinges on three items:

- Levels of production of oil and gas
- Wellhead prices of oil and gas
- The level of profitability of the industry.

For the initial appraisal, the future production of crude oil and natural gas (excluding the North Slope production) is projected to decline from the 1970 level. Throughout the projection period the task group held the price of crude oil constant, and allowed the price of natural gas to rise only modestly. Accordingly, the producing industry's gross income (referred to as "net wellhead value" in Volume One) declines from $12.75 billion in 1970 to $11.2 billion in 1985.

The increase in capital requirements, coupled with a decline in gross income, results in a sharp increase in the proportion of gross income *required* to be reinvested in order to sustain the assumed rate of exploration and drilling activity from 38 percent in 1970 to 65 percent in 1985.

To rigorously determine the *funds available* for reinvestment many items must be deducted form the industry's gross income. These include operating costs, production and *ad valorem* taxes, state and federal income taxes, dividend payments, repayments of debt and necessary additions to working capital. Calculation of all of these items has not been attempted in Phase I of the study.

The trend in investment requirements and their impact on the industry can be assessed at least directionally from an examination of the percent of gross income required to meet new investment requirements. The calculation of values for percent of gross income required to be reinvested is shown for oil, gas and industry total in Tables LII, LIII and LIV (pp. 74-76). This indicator declined from 53 percent in 1960 to 38 percent in 1970. The main inference to be drawn from this decline is that during that decade the industry believed it had better investment opportunities outside the domestic producing segment of the petroleum producing industry.

Against a projection background which includes no increase in crude oil prices and only modest increases for natural gas, it is considered unlikely that the industry would recognize any incentive to increase the proportion of its gross income to be reinvested in the domestic producing industry.

If the reinvested income were held to 38 percent of gross income, the 1985 internally generated funds available for capital investment would be reduced by $3 billion, and this amount would have to be obtained from other sectors.

The task group made no attempt to develop a statement of the source and disposition of funds for the exploration and producing function beyond reflecting capital needs in terms of percent of revenue reinvested.

ASSUMPTIONS

The necessary data for exploration and development capital needs were developed by the Oil and Gas Supply Task Groups (see oil and gas supply sections of this volume for details on the derivation of these costs).

The Capital Requirements Task Group made the following assumptions in order to relate capital expenditures to revenue generated from oil and gas operations:

- Wellhead price of crude oil would remain at the current average level of $3.35/B.

- Forty percent of the current plant value of liquids would be assigned to the leaseholder.

- Currently contracted gas would have an average wellhead price of 16.7¢/MCF, with a 1¢/MCF escalation every 5 years; new gas would have an average value of 22.33¢/MCF for Onshore and 26¢/MCF for South Louisiana.

- Royalty costs would be 13.5 percent of wellhead price.

METHODOLOGY

The methodology of allocating historical capital investments to the oil and gas businesses is outlined below:*

- Drilling investments for successful wells were assigned to the oil or gas business based on the type of completion made.

- Dry-hole drilling costs were allocated between oil and gas in the same proportion as successful wells.

- Service well investments were allocated to oil.

- Lease bonus payments were generally assigned to oil or gas on the basis of whether the area in which they were made is considered mainly oil or gas bearing.

- Geological and geophysical expenses and lease rentals were generally divided between oil and gas based on the percentage of exploratory wells drilled for each.

The foregoing historical cost allocation technique was used as the basis for the future projections of capital requirements by the Oil and Gas Supply Task Groups. The following is a more detailed discussion of the methodology that was employed.

Petroleum exploration is directed toward the discovery of oil *and* gas. While some operators may be interested more in one than the other, and some petroleum provinces may be preferentially oil or gas prone, this is nevertheless one business, one technology. For the purpose of analyzing historical investments, however, it is convenient to view the petroleum exploration and development industry as two separate businesses carried on by the same company. The "oil business" is concerned with the discovery and production of crude oil as the main product, and associated natural gas and gas liquids as the by-products. Conversely, nonassociated natural gas is the principal product

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*Abstracts from a paper by John D. Emerson and Harold D. Hammar presented March 9, 1971, at the Symposium on Petroleum Economics and Evaluation, Dallas, Texas.

involved in the "gas business," with nonassociated gas liquids and lease condensate as by-products. Each of these products has economic value to the producer, each involves him in costs, and each contributes to the return on his investment and subsequently to the funds available for reinvestment.

In this analysis, investment funds have not been allocated between oil and natural gas, but between the "oil business" and the "gas business," which are defined on the basis of the principal product sought, as mentioned above. Rather than use an arbitrary formula, either involving BTU's or relative price, each of the areas of specific direct cost has been analyzed and expenditures allocated to the "oil business" or the "gas business" in a logical manner.

In this allocation of funds, investment values have been used which represent the average of the latest 10 years for which data are available. These numbers are taken from the Chase Manhattan Bank's annual publication, *Capital Investments of the World Petroleum Industry*.

Table XLVII gives the basic breakdown of total exploration and development expenditures by the domestic producing industry over the last 10 years.

TABLE XLVII

DOMESTIC PRODUCING INDUSTRY
EXPLORATION AND DEVELOPMENT EXPENDITURES*
(Million Dollars)

Producing Wells	$2,161
Dry Holes	871
Lease Acquisitions	717
Geological and Geophysical Costs	474
Lease Rentals	155
TOTAL	$4,378

* Average latest 10 years' data.

Of the total expenditures for all exploration and development purposes, one-half represents the cost of drilling and equipping producing wells. In apportioning the cost of these producing wells between the "oil business" and the "gas business" for this analysis, the basic assumption has been made that operators were looking for what they found. In other words, if the expenditure of a sum of money resulted in a successful oil well, then that expenditure was charged to the "oil business," regardless of the original intentions of the operator.

Using published data on the number of successful exploratory and development oil and gas wells resulted in the cost allocation shown in Table XLVIII.

TABLE XLVIII

COST OF PRODUCING WELLS*
(Million Dollars)

	Oil Business	Gas Business	Combined
Exploratory Wells	80	76	156
Development Wells	1,534	471	2,005
TOTAL	1,614	547	2,161

* Average latest 10 years' data.

This allocation takes into account the cost implications of the difference in depth between exploratory and development wells, and between oil and gas wells. During this 10-year period, the investment in drilling exploratory wells was about the same in the "oil business" as in the "gas business." For development wells, however, more than three times as much was spent by the "oil business" as the "gas business." This reflects the fact that far more wells are required to develop an oil field than a gas field of equivalent size. The cost of service wells, such as water or gas injection wells, was allocated to the "oil business" as these are generally associated with oil production.

The next largest item of expenditure is the cost of dry holes. One-fifth of the total amount spent on exploration and development during this decade--$871 million a year--was devoted to this nonproductive but necessary research type activity. Dry holes do not produce oil or gas, but they certainly help to find it.

Satisfactory data exist on the actual number of dry holes, classified by the industry as exploratory or developmental. Not surprisingly, the number of exploratory dry holes account for two-thirds of the total. At this stage in the game, the industry is primarily looking for hydrocarbon-bearing structures rather than oil or gas specifically. In a sense, dry-hole costs are a form of "research" expenditure, and one allocation of these costs between the "oil business" and the "gas business" would therefore be in the same proportion as the number of successful wells adjusted for differences in per well costs due to depth, etc. It must be recognized, however, that this is an oversimplification adopted as an analytical expedient. At the development drilling stage, even though there are no separate figures for dry holes drilled in oil and gas fields, it was assumed that the industry enjoys the same relative success ratio in the development of both oil and gas. The results of these allocations are shown in Table XLIX.

TABLE XLIX

COST OF DRY HOLES*
(Million Dollars)

	Oil Business	Gas Business	Combined
Exploratory Holes	273	301	574
Development Holes	206	91	297
TOTAL	479	392	871

* Average latest 10 years' data.

Almost as large as the expenditures made for dry holes are the non-productive lease bonus payments made mainly to government--over $700 million a year in this decade. In contrast with the situation for dry holes, these lease bonus payments do not add any information which is valuable in the search for oil and gas deposits. To be consistent, these leases should be explored and fully developed before allocating the costs in proportion to the successful oil and gas wells drilled on them. In order to use the most recent data, however, these costs have been allocated on the basis of whether the areas involved are generally considered by the industry to be mainly oil bearing or gas bearing.

Two other items of exploratory cost complete the list--geological and geophysical expenses and lease rentals. These are, strictly speaking, non-capital items, but they are usually included in the total exploration and development expenditures. These items have been divided between the "oil business" and the "gas business" on the basis of the proportion of exploratory oil and gas wells drilled.

The allocation of lease bonus payments, geological and geophysical expenses and lease rentals to the "oil business" and "gas business" is shown in Table L.

TABLE L

OTHER EXPENDITURES*
(Million Dollars)

	Oil Business	Gas Business	Combined
Lease Acquisitions	500	217	717
Geological and Geophysical Costs	303	171	474
Lease Rentals	94	61	155

* Average latest 10 years' data.

Table LI summarizes the allocations of the various exploration and development costs listed in Table XLVII between the "oil business" and the "gas business."

TABLE LI

DOMESTIC PRODUCING INDUSTRY
EXPLORATION AND DEVELOPMENT EXPENDITURES*
(Million Dollars)

	Oil Business	Gas Business	Combined
Producing Wells	1,614	547	2,161
Dry Holes	479	392	871
Lease Acquisitions	500	217	717
Geological and Geophysical Costs	303	171	474
Lease Rentals	94	61	155
TOTAL	2,990	1,388	4,378

* Average latest 10 years' data.

During this decade, more than two-thirds of the total investment was made by the "oil business" and just under one-third by the "gas business."

RESULTS

PRODUCTION VOLUMES

Production volumes were obtained from the Oil and Gas Supply Task Groups. (See those sections for more detail.) Natural gas liquids produced prior to 1966 were allocated to associated and nonassociated categories in proportion to associated and nonassociated gas reserves.

PERCENT OF GROSS INCOME REINVESTED

The capital costs and production volumes for the oil and gas segments of the petroleum industry were used, together with the assumptions indicated above, to analyze the relationship of capital requirements to gross income generated from production. This analysis is detailed in the following three tables.

TABLE LII

OIL BUSINESS (LOWER 48 STATES)

		Actual		Projected		
		1960	1970	1975	1980	1985
1.	Crude Oil Production (excludes Condensate)--MMB	2,474	3,319	3,120	2,960	2,900
2.	Wellhead Price--$/bbl	2.87	3.13	3.35	3.35	3.35
3.	Crude Oil Value--$ million (line 1 x line 2)	7,109	10,388	10,452	9,916	9,715
4.	Associated Natural Gas Production (TCF)	3.7	4.8	4.2	3.8	2.3
5.	Gas Price at Well--¢/MCF (excludes value of liquids)	11.0	15.0	16.3	18.6	20.5
6.	Associated Gas Value--$ million (line 4 x line 5)	407	728	685	707	472
7.	Associated NGL Production--MMB	198	256	229	218	131
8.	Lease Value of Associated NGL--$/bbl	.96	.88	.8	.8	.8
9.	Associated NGL Value--$ million (line 7 x line 8)	190	233	183	174	105
10.	Total Value of Production--$ million (lines 3 + 6 + 9)	7,706	11,349	11,320	10,797	10,292
11.	Payments to Royalty Owners--$ million	1,040	1,532	1,528	1,458	1,389
12.	Gross Income to Industry--$ million (line 10 - line 11)	6,666	9,817	9,792	9,339	8,903
13.	Capital Investments--$ million	2,845	2,800	3,910	4,620	5,360
14.	Percent of Gross Income Reinvested (line 13 x 100/line 12)	43	29*	40	49	60

* 1970 figure of 29-percent gross income reinvested differs from the 28 percent reported in Volume One because more recent revenue data have been incorporated into these statements.

NOTES:

Line 1--Actual from API Reserves Committee. Projection from NPC Oil Supply Task Group.
Line 2--Actual from U.S. Bureau of Mines. Projection by NPC Oil Supply Task Group.
Line 4--Actual based on AGA Reserves Committee data. Projection from NPC Gas Supply Task Group, based on associated gas reserve additions from the Oil Supply Task Group.
Line 5--Actual calculated from U.S. Bureau of Mines data. Projection by NPC Gas Supply Task Group.
Line 7--Actual based on AGA Reserves Committee data. Projection from NPC Gas Supply Task Group.
Line 8--Actual based on U.S. Bureau of Mines data. Forty percent of plant value of liquids is allocated back to the producer. Projection by NPC Capital Requirements Task Group.
Line 11--Gross royalty payments are estimated to be 15 percent. It is believed, however, that about 10 percent of royalty payments accrue to producing concerns. Net royalty payments equal to 13.5 percent of wellhead value have accordingly been used.
Line 13--Actual estimated by Chase Manhattan Bank. Projections made by Chase Manhattan Bank based on data supplied by the NPC Oil Supply Task Group.

TABLE LIII

GAS BUSINESS (LOWER 48 STATES)

	Actual		Projected		
	1960	1970	1975	1980	1985
1. Nonassociated Gas Production (TCF)	9.4	17.1	15.6	12.5	10.7
2. Wellhead Price--¢/MCF (excludes value of liquids)	11.0	15.0	16.3	18.6	20.5
3. Nonassociated Gas Value--$ million (line 1 x line 2)	1,028	2,568	2,542	2,325	2,194
4. Nonassociated NGL Production--MMB	141	357	329	217	173
5. Lease Value of Nonassociated NGL--$/bbl	.96	.88	.8	.8	.8
6. Nonassociated NGL Value--$ million (line 4 x line 5)	135	314	263	174	138
7. Condensate Production--MMB	92	134	140	109	76
8. Wellhead Price--$/bbl	3.37	3.63	3.85	3.85	3.85
9. Condensate Value--$ million (line 7 x line 8)	310	486	539	420	293
10. Total Value of Production--$ million (lines 3 + 6 + 9)	1,473	3,368	3,344	2,919	2,625
11. Payments to Royalty Owners--$ million	199	455	451	394	354
12. Gross Income to Industry--$ million (line 10 - line 11)	1,274	2,913	2,893	2,525	2,271
13. Capital Investments--$ million	1,355	2,000	1,836	1,856	1,882
14. Percent of Gross Income Reinvested (line 13 x 100/line 12)	106	69*	63	74	83

* 1970 figure of 69 percent of gross income reinvested differs from the 67 percent reported in Volume One because more recent revenue data have been incorporated into these statements.

NOTES:

Line 1--Actual from AGA Reserves Committee. Projection from NPC Gas Supply Task Group.
Line 2--Actual calculated from U.S. Bureau of Mines data. Projection by NPC Gas Supply Task Group.
Line 4--Actual based on AGA Reserves Committee data. Projection from NPC Gas Supply Task Group.
Line 5--Actual based on U.S. Bureau of Mines data. Forty percent of plant value of liquids is allocated back to the producer. Projection by NPC Capital Requirements Task Group.
Line 7--Actual based on AGA Reserves Committee data. Projection from NPC Gas Supply Task Group.
Line 8--Value of condensate was estimated by the NPC Capital Requirements Task Group to be 50¢ a barrel above the value of crude oil.
Line 11--Gross royalty payments are estimated to be 15 percent. It is believed, however, that about 10 percent of royalty payments accrue to producing concerns. Net royalty payments equal to 13.5 percent of wellhead value have accordingly been used.
Line 13--Actual estimated by Chase Manhattan Bank. Projection Supplied by NPC Gas Supply Task Group.

TABLE LIV

OIL AND GAS COMBINED (LOWER 48 STATES)

	Actual		Projected		
	1960	1970	1975	1980	1985
Gross Income to Industry--$ million	7,940	12,750	12,657	11,886	11,205
Capital Investments--$ million	4,200	4,800	5,746	6,476	7,242
Percent of Gross Income Reinvested	53	38*	45	54	65

* 1970 figure of 38 percent of gross income reinvested differs from the 37 percent reported in Volume One because more recent revenue data have been incorporated into these statements.

Chapter Six

Gas Task Group

Gas Supply

GAS SUPPLY TASK GROUP

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GAS SUPPLY TASK GROUP REPORT

ABSTRACT

Gas markets, in recent years, have been characterized by rapidly increasing demand and lagging additions to supply. Supply limitations are now beginning to restrict demand growth. Following are several major factors pertinent to the future of gas supply:

- There remains to be discovered 795 TCF of natural gas in the lower 48 states and 432 TCF in Alaska for a total of 1,227 TCF.*

- Based on the assumptions set for the initial appraisal, the natural gas reserve additions for the period 1971-1985 are estimated to be 141 TCF (145.51 quadrillion BTU's), which is a little more than 10 percent of the remaining potential.

- Costs and prices of liquefied natural gas (LNG), natural gas from the North Slope and Canadian Arctic, and gas from coal and liquid hydrocarbons will be substantially higher than those for currently produced domestic natural gas.

- Conventional exploration and development of natural gas reserves in the lower 48 states and adjacent offshore areas offer: (1) the greatest and earliest potential sources of additional gas supplies, (2) the most economical sources of gas supply, and (3) the most secure sources of gas supply.

- Capital requirements for the period 1971-1985 for exploration and development of natural gas in the United States are estimated at $27.735 billion.

- Because of the resource base adequacy, production rates and supply volumes could be largely expanded by an increase in drilling activity which is a reflection of added economic incentives.

- Domestic natural gas production for 1970 and estimated production from the lower 48 states for the years 1975, 1980 and 1985, and the estimated total gas supply (including synthetic pipeline gas and imports), are as follows:

Year	Lower 48 States (TCF)	Total Gas Supply (TCF)
1970	21.82	22.74
1975	19.80	21.72
1980	16.30	21.77
1985	13.00	21.49

**Potential Supply of Natural Gas in the United States (as of December 31, 1968)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1969).

- Indicated shortfalls in the gas supply are as follows:

	Trillion Cubic Feet
1975	7.60
1980	11.84
1985	17.38

The following sections of this chapter describe the underlying assumptions and resulting projections concerning gas supply and gas reserve additions. These are, in turn, followed by discussion of the factors governing the projection. Particular emphasis is given to nonassociated gas reserves which constitute the largest single component of gas supply.

SUMMARY OF THE GAS SUPPLY TASK GROUP REPORT

ASSUMPTIONS

The initial appraisal analysis by the Gas Supply Task Group of the Gas Subcommittee, for the 15-year period 1971-1985, involves projecting (1) domestic nonassociated natural gas supply and liquefied petroleum gas (LPG) availability; (2) imports of natural gas from Canada, Mexico and the North Slope of Alaska; (3) imports of LNG; and (4) the manufacture of pipeline quality gas utilizing synthetic gas technology. Projections of the associated and dissolved natural gas reserve additions were furnished by the Oil Supply Task Group of the Oil Subcommittee.

Actual production is shown for the year 1970, and future producing rate levels have been projected for the years 1975, 1980 and 1985. Projections of domestic wellhead production are shown by region, utilizing the geographical boundaries applied in the National Petroleum Council's *Future Petroleum Provinces of the U.S.* report.

Projections for this initial appraisal have been made on the basis of the assumptions described herein which relate to government policy, wellhead price regulation and logistics. Projections have also been made for capital requirements and operating expenses supporting the projections of reserve additions and production.

The following assumptions were utilized by the Gas Supply Task Group for the initial appraisal.

1. *For Natural Gas Reserve Additions Through 1985.*

- Reserve additions for the lower 48 states are attributable to the Potential Gas Committee's "probable" reserve category.* Projections for the North Slope of Alaska are based on the task group judgment that oil exploration activity will provide virtually all natural gas reserve additions during the study period.

- A nationwide new wellhead gas price of 22.33¢ per MCF for the United States, except South Louisiana, and 26¢ per MCF for South Louisiana. (These base prices were escalated at the rate of 1¢ per MCF every 5 years.) The nationwide price of 22.33¢ per MCF will be at 14.65 PSIA pressure base excluding state production taxes, while the South Loui-

**Potential Supply of Natural Gas in the United States (as of December 31, 1968),* a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1969).

siana price is at 15.02 PSIA and includes state production taxes. Adjustments for BTU content will be recognized in the above price structure which follows the suggestions of the Federal Power Commission staff in Docket R-389-A.

- State and federal government agencies will continue to offer offshore oil and gas leases in the lower-48-state area covering approximately one-half million acres of land each year. This expectation, stated as an average, is consistent with past experience.

- There will be no appreciable changes in present federal policies regarding tax incentives and oil import controls.

- A minimum of three years will be required to mobilize the equipment and personnel necessary to raise current drilling levels sufficiently to achieve the maximum level of annual reserve additions projected.

- Some delay between the time of discovery and the subsequent production of new gas reserves is normally unavoidable. In more remote areas of the lower 48 states, delays of 18 months for onshore and three years for offshore may be assumed. Alaskan discoveries may experience a more lengthy delay.

- Production levels of natural gas were estimated by assuming a reserves/production (R/P) ratio of 10 in each of the NPC regions; for those regions where the R/P ratio is currently above 10, production was increased at a 6-percent annual rate over the prior year until an R/P ratio of 10 was attained. Based on industry experience, an R/P of 10 was regarded as the minimum that could be tolerated without significant and recurrent curtailments in service.

2. *For Pipeline Imports*

- The United States now receives and will continue to receive pipeline gas imports.

- The imports from Mexico are small and are not expected to increase. It is contemplated that existing contracts governing imports from Mexico will not be renewed.

- The import volumes from Canada are assumed to be those which the Canadian National Energy Board has declared to be "surplus beyond Canada's requirement" and available for export.

- The first natural gas pipeline from the North Slope of Alaska to the lower 48 states will be supported by the North Slope Alaskan reserves discovered to date. Gas production will not be marketed until a crude oil transportation system is completed. No new complete gas pipeline system will be added until further natural gas reserves are developed to support such a system. However, incremental looping capacity may be added to the initial system.

3. *For LNG Supplies*

- Sufficient reserves will be available from each source of supply to support projects with the volumes indicated in this report for at least 20 years. The minimum quantity of gas reserves required for a viable LNG project was considered to be 12.5 BCF for each M^2CF/D delivered.

- Due to the sizable capital requirements to mount an LNG project, such projects must be capable of delivering a minimum of 500 M^2CF/D at the point of regasification over a 20-year period. This does not preclude consideration of smaller-volume projects where the political climate at the source of supply is considered stable, supply is essentially at the shore, and hauling distance is relatively short so that a minimum of 300 M^2CF/D might be considered.

- The price structure for LNG at all points--field, f.o.b., c.i.f. and after revaporization--will be sufficiently attractive to engender the investment(s) necessary for an LNG supply project.

- The monies required will be available to finance the various LNG projects contemplated.

- Shipyard capacity will be available for the construction of the LNG tankers required, assuming that the LNG tankers needed will be at least in the 750,000-barrel class with a draft of 36 feet.

- Regulatory authorities in the producing and consuming countries, whether international, national or local, will grant the needed permits.

4. *For Synthetic Pipeline Gas*

- Production will be limited to the reforming of petroleum liquids and to the gasification of domestic coal.

- Reforming technology is known, but the product prices will be significantly above current domestic natural gas prices.

- Coal gasification technology is known for low-BTU gas, and the process for pipeline quality gas is under development.

5. *For Liquefied Petroleum Gas*

- Natural gas production will occur as projected, based upon the reserve additions projected in this report.

- Historical trends as to gas composition and processing levels at gas plants will not change.

6. *For Liquefied Petroleum Gas Imports*

- Projections of U.S. LPG imports were based on estimates, by continent, of the Free World's future supply and demand of LPG. In general, imports from Western Hemisphere sources are expected to continue with essentially no restrictions. It is further assumed that any existing restrictions on sources from other areas of the Free World will be relaxed before the end of the 1970's.

- A majority of the excess supplies from the Western Hemisphere are expected to be marketed in the United States throughout the forecast period. Future developments are expected to result in Eastern Hemisphere exports to the United States commencing in the late 1970's.

TOTAL GAS SUPPLY PROJECTION

U.S. gas supply in 1970 and the projections of future supply in the years 1975, 1980 and 1985, based on the foregoing assumptions, are shown in Table LV. There is a decline in wellhead production in the lower 48 states from 21.82 TCF in 1970 to 13.0 TCF in 1985. Total gas supply available to the United States was 22.74 TCF in 1970 and is projected to decline to 21.49 TCF in 1985. The 8.82 TCF decline in wellhead production in the lower 48 states from 1970 to 1985 is largely offset by imported LNG, imported LPG natural gas from Alaska's North Slope and synthetic pipeline gas, all of which involve costs and prices substantially in excess of those for currently produced domestic natural gas.

TABLE LV

GAS SUPPLY FOR U.S.
(Quadrillion BTU's)

	1970		1975		1980		1985	
	TCF	BTU	TCF	BTU	TCF	BTU	TCF	BTU
U.S. (Except North Slope)	21.82	22.52	19.80	20.43	16.30	16.82	13.00	13.41
North Slope	---	---	---	---	1.17	1.21	1.50	1.55
Synthetic P/L Gas	---	---	0.37	0.38	0.55	0.57	0.91	0.94
Total Domestic Supply	21.82	22.52	20.17	20.81	18.02	18.60	15.41	15.90
Imports:								
Canada	0.83	0.86	1.15	1.19	1.15	1.19	1.15	1.19
Mexico	0.05	0.05	0.05	0.05	---	---	---	---
LNG	---*	---	0.18	0.19	2.10	2.17	4.00	4.13
LPG	0.04	0.04	0.17	0.18	0.50	0.52	0.93	0.96
Total Imports	0.92	0.95	1.55	1.61	3.75	3.88	6.08	6.28
TOTAL GAS SUPPLY	22.74	23.47	21.72	22.42	21.77	22.48	21.49	22.18

* Less than 10 BCF per year.

Reserve additions for the lower 48 states for the periods 1971-1975, 1976-1980 and 1981-1985 are shown in Table LVI under the categories of "non-associated" and "associated and dissolved" gas.

TABLE LVI

RESERVE ADDITIONS 1971-1985
LOWER 48 STATES*
(Quadrillion BTU's)

	Total		Nonassociated		Associated & Dissolved	
	(TCF)	(BTU)	(TCF)	(BTU)	(TCF)	(BTU)
1971-75	50	51.60	43.52	44.91	6.48	6.69
1976-80	52	53.66	46.34	47.82	5.66	5.84
1981-85	39	40.25	33.86	34.95	5.14	5.30
TOTAL	141	145.51	123.72	127.68	17.28	17.83

* Nonassociated estimated from the Gas Supply Task Group, Gas Subcommittee. Associated and dissolved estimate from the Oil Supply Task Group, Oil Subcommittee.

Actual reserve additions for the lower 48 states and Alaska for the years 1966 through 1969, the preliminary estimate of 1970 additions and the projections for the years 1971 through 1985 are shown in Table LVII. Volumes of natural gas reserve additions under the categories of "associated and dissolved" and "nonassociated" for the lower 48 states, Alaskan North Slope and offshore are shown in Table LVIII for the years 1970, 1975, 1980 and 1985. Also shown on Table LVIII for the same years are natural gas liquids, condensate and gas plant liquids.

TABLE LVII

NATURAL GAS RESERVE ADDITIONS*
(Trillion Cubic Feet)

	Lower 48 States	Alaska	Total
	Actual		
1966	19.3	0.9	20.2
1967	21.1	0.7	21.8
1968	12.0	1.7	13.7
1969	8.3	---	8.3
	Projected		
1970	11.0	26.0	37.0
1971	8.0	0.0	8.0
1972	10.0	1.0	11.0
1973	10.0	1.0	11.0
1974	11.0	1.0	12.0
1975	11.0	1.0	12.0
1976	11.0	1.0	12.0
1977	11.0	1.0	12.0
1978	10.0	1.0	11.0
1979	10.0	1.0	11.0
1980	10.0	1.0	11.0
1981	9.0	2.0	11.0
1982	8.0	2.0	10.0
1983	8.0	2.0	10.0
1984	7.0	2.0	9.0
1985	7.0	2.0	9.0
1966-1970	71.7	29.3	101.0
1971-1975	50.0	4.0	54.0
1976-1980	52.0	5.0	57.0
1981-1985	39.0	10.0	49.0

* Reserve additions for the lower 48 states are attributable to the Potential Gas Committee's "Probable" reserve category (see p. 106). Projections for the North Slope of Alaska are based on the task group judgment that oil exploration activity will provide virtually all natural gas reserve additions during the study period.

TABLE LVIII

SUMMARY OF DOMESTIC GAS AND GAS LIQUID SUPPLY

	Total Gas			A & D		N A		NGL		Condensate	Gas Plant Liquids				
	Res Adds (TCF)	Prod. (TCF)	Year End Res (TCF)	Prod. (TCF)	Year End Res (TCF)	Prod. (TCF)	Year End Res (TCF)	Prod. (MMB)	Year End Res (MMB)	Prod. (MMB)	Total (MMB)	Ethane (MMB)	Propane (MMB)	Butane (MMB)	Pentane (MMB)
48 States															
1970	11.1	21.8	259.6	4.8	56.3	17.0	203.3	747	7,703	134	613	66	210	144	193
1975	11.0	19.8	203.1	4.2	40.7	15.6	162.4	698	5,321	140	558	60	191	131	176
1980	10.0	16.4	166.8	3.8	25.8	12.6	141.0	556	3,662	111	446	48	153	105	140
1985	7.0	13.0	134.4	2.3	18.1	10.7	116.3	380	2,569	76	305	33	104	72	96
Alaskan North Slope															
1970	26.0	---	26.0	---	26.0	---	---	---	---	---	---	--	---	---	---
1975	1.0	---	30.0	---	30.0	---	---	---	---	---	---	--	---	---	---
1980	1.0	1.2	30.5	1.2	30.5	---	---	40	905	10	30	--	22	7	1
1985	2.0	1.5	33.7	1.5	33.7	---	---	51	1,014	13	39	--	28	9	2
TOTALS															
1970	37.1	21.8	285.6	4.8	82.3	17.0	203.3	747	7,703	134	613	66	210	144	193
1975	12.0	19.8	233.1	4.2	70.7	15.6	162.4	698	5,321	140	558	60	191	131	176
1980	11.0	17.6	197.3	5.0	56.3	12.6	141.0	596	4,567	121	476	48	175	112	142
1985	9.0	14.5	168.1	3.8	51.8	10.7	116.3	431	3,583	89	344	33	132	81	98
Data for the Offshore Area - NPC Region 6A (data included in above totals)															
1970	5.3	2.8	37.8	.446	5.7	2.377	32.1	61	922	12	49				
1975	1.5	2.9	29.3	.401	6.9	2.532	22.4	65	734	13	52				
1980	1.4	2.4	23.7	.451	7.8	1.915	15.9	51	617	10	41				
1985	1.0	1.9	18.7	.451	8.4	1.424	10.3	39	517	8	31				

RATIONALE

1. Introduction

All estimates of original gas-in-place in the lower 48 states and Alaska, onshore and offshore, greatly exceed production to date. The Gas Supply Task Group relied upon the Potential Gas Committee report* to provide the resource base. (Under that assumption, future gas supply through the turn of the century could be assured if discoveries of sufficient magnitude occur on a timely basis.) Therefore, the projections made by the Gas Supply Task Group for the period 1971-1985, as shown in this summary, are not restricted by limitations on potentially available reserves. These projections reflect only the judgment of what is expected to occur in terms of future gas supply under the conditions assumed for the initial appraisal.

Guidance in the selection of a regulated wellhead price for purposes of this study effort was provided by consideration of a pertinent Federal Power Commission proceeding. The recommendation by the staff of the Federal Power Commission (Docket R-389-A) of 22.33¢ per MCF as of 1969, exclusive of state production taxes, was the one adopted for purposes of this study for new gas in all areas except South Louisiana. The South Louisiana price recommended by the staff of the FPC in the same proceeding, of 26¢ per MCF (including state production taxes), was adopted for this initial appraisal.

The Gas Supply Task Group does not endorse or reject the prices utilized. Its analysis reflects only its judgment of the effects of the prices assumed to be in effect during the initial appraisal study period 1971-1985.

2. General

The Gas Supply Task Group projection of 123.72 TCF of nonassociated gas reserve additions, when added to the 17.28 TCF of associated and dissolved gas reserve additions projected by the Oil Supply Task Group, results in gross additions to reserves of 141 TCF for the study period 1971-1985 (see Table LVI, p. 81). During the 21-year period 1950-1970, associated and dissolved gas represented approximately 24.5 percent of annual additions to reserves as contrasted to only 12.26 percent during the period 1971-1985. The reason for this departure from past experience is that a much larger proportion of future oil production is attributed to secondary and tertiary recovery operations which do not result in associated and dissolved gas reserve additions.†

For purposes of a comparison relating to nonassociated gas reserve additions, a purely statistical trend analysis projection is shown with the task group projection in summary form in Table LIX.

The independent statistical projection is 29.28 TCF higher than the task group forecast, a difference averaging slightly less than 2 TCF per year. This independent projection was neither influenced by the continued significant decline in the number of wells drilled (see Table LX) nor by the results experienced in the years 1968, 1969 and 1970 when reserve additions in the lower 48 states declined rather dramatically. On the basis of those factors and the following discussion which provides the detail and perspective governing the Gas Supply Task Group projections, this difference appears reasonable.

**Potential Supply of Natural Gas in the United States (as of December 31, 1968)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (Golden, Colorado, October 1969).

†For a more detailed discussion see the Oil Supply Task Group Report.

TABLE LIX

COMPARISON OF NONASSOCIATED RESERVE ADDITIONS--1971-1985
(TCF)

	Task Group Forecast	Independent Projection*	Difference (Col.2 v. Col.1)
1971-75	43.52	54.0	(10.48)
1976-80	46.34	51.0	(4.66)
1981-85	33.86	48.0	(14.14)
TOTAL	123.72	153.0	(29.28)

* Analysis and projection for the National Petroleum Council by Mr. C. L. Moore, Petroleum Consultant, based on application of statistical trend analysis (Gompertz Curve) to American Gas Association historical data for the years *1930-1962*, a 32-year period indicating high correlation of significance from linear regression analysis.

3. *Nonassociated Gas Reserve Projection*

Natural gas reserve additions in the lower 48 states in the years 1968, 1969 and 1970 were below consumption levels and significantly below the levels of reserve additions for each year since 1954. Much of this decrease can be attributed to the level of drilling activity. Table LX shows a 31-percent decline in the number of gas well completions between 1961 and 1969. There are many economic factors responsible for this situation.

Based on Table LX data, there has been a 12-percent increase in average gas well depth during the period 1961-1969 in contrast to a well cost increase of approximately 62 percent. During the same time interval, there has been a small wellhead price increase for regulated production which, in terms of constant 1970 dollars, results in a net decrease in the price received by the producer. The initial appraisal seeks to present the forecasts and projections in terms of 1970 dollars. However, the mode of regulatory price control of gas sold interstate requires consideration of the assumptions described herein for prospective wellhead prices. Table LXI displays the *average* wellhead price by year for the period 1961-1970 and the wellhead price for *new gas* during the period 1971-1985 in terms of constant 1970 dollars.

Examination of Table LXI, column 3, reveals the extent of the constant dollar decline in wellhead price during the 1961-1970 interval. As a result, the price increase for new gas in 1971 is slightly greater in relation to the 1970 price than it is to the 1961 price when all are expressed in constant dollars. Column 3 also shows that a 1¢/MCF increase at 5-year intervals does not keep pace with the modest 2.7-percent annual inflationary factor used for illustrative purposes.

The initial effect of the higher regulated price assumed for new gas on gross income to the producer segment of the industry will be limited because the major share of production involved lower-priced *old* gas. Other factors tending to partially offset the positive influence of a higher wellhead price are the economic consequences of the Tax Reform Act of 1969 accompanied by the lowering of the depletion allowance from 27.5 percent to 22 percent.

TABLE LX

OIL AND GAS WELL STATISTICS

	1969	1968	1967	1966	1965	1964	1963	1962	1961
Av. Drilling Cost/Well ($000)									
Oil	86.5	79.1	66.6	62.2	56.6	50.6	51.8	54.2	51.3
Gas	154.3	148.5	141.0	133.8	101.9	104.8	92.4	97.1	94.7
Dry	70.2	66.2	61.5	56.9	53.1	48.5	48.2	50.8	45.2
All Wells	88.6	81.5	72.9	68.4	60.6	55.8	55.0	58.6	54.5
Av. Drilling Cost/Foot ($)									
Oil	19.28	18.63	16.61	15.04	13.94	13.12	13.20	13.41	13.11
Gas	25.58	24.05	23.05	21.75	18.35	18.57	17.19	18.10	17.65
Dry	13.23	12.88	12.87	12.34	11.21	10.64	10.58	11.20	10.56
All Wells	17.56	16.83	15.97	14.95	13.44	12.86	12.69	13.31	12.85
Av. Depth (Feet/Well)									
Oil	4,486	4,246	4,013	4,134	4,059	3,854	3,922	4,041	3,911
Gas	6,034	6,177	6,116	6,151	5,552	5,641	5,373	5,366	5,366
Dry	5,307	5,137	4,777	4,614	4,739	4,560	4,556	4,533	4,284
Total	5,044	4,839	4,566	4,575	4,513	4,340	4,336	4,405	4,244
No. Wells (000)									
Oil	12.9	13.8	14.9	15.9	18.9	21.0	20.1	21.4	21.2
Gas	3.9	3.3	3.6	4.1	4.8	4.8	4.8	5.9	5.7
Dry	12.6	12.4	13.0	14.6	16.0	17.6	16.3	16.7	17.1
Total	29.5	29.6	31.5	34.5	39.6	43.5	41.9	43.9	44.0
Prices (¢/MCF) Natural Gas @ Well	16.7	16.4	16.0	15.7	15.6	15.4	15.8	15.5	15.1

Coupled with the cost and price factors discussed above is the disappointing downward trend in nonassociated gas reserves found per foot of gas well drilled, as illustrated in Figure 11. The graph pictured also shows that the Gas Supply Task Group projection is above the level of the experience trend for the last 5 years. From 1971 on, a recovery from recent poor results is indicated. By 1976 the projection rises above an extrapolation of 1950-1969 experience and remains above that trend for the remainder of the study period.

The relationship between increasing gas well costs and downward trend in nonassociated gas reserve additions resulting from drilling can be directly translated into an expenditure analysis. Figure 12 illustrates historical experience in nonassociated gas reserve additions per dollar spent for exploration and development drilling. Curves extrapolating 1952-1969 data and 1965-1969 data are shown for comparison.

In the late 1960's a turning point is evident, with costs rapidly escalating and nonassociated reserve additions declining. This can be largely attributed to the higher costs of drilling including inflationary factors, drilling

TABLE LXI

NATURAL GAS WELLHEAD PRICE--ACTUAL AND DEFLATED
(Wellhead Price Increases 1¢/MCF at 5-Year Intervals)

Year	Price Index 1970 = 100*	Wellhead Price/MCF (USBM)	Price Col.2 Adjusted by Index Col.1	Wellhead Price/MCF South La.	Price Col.4 Adjusted by Index Col.1
1961	85.58	15.1	17.64		
1962	85.84	15.5	18.05		
1963	85.58	15.8	18.46		
1964	85.75	15.4	17.95		
1965	87.46	15.6	17.83		
1966	90.36	15.7	17.37		
1967	90.53	16.0	17.67		
1968	92.83	16.4	17.66		
1969	96.42	16.7	17.32		
1970	100.00	17.1	17.10		
1971	102.60	22.33†	21.76	26.0	25.34
1972	105.37		21.19		24.67
1973	108.22		20.63		24.03
1974	111.14		20.09		22.39
1975	114.14		19.56		22.78
1976	117.22	23.33	19.90	27.0	23.03
1977	120.38		19.38		22.43
1978	123.63		18.87		21.84
1979	126.97		18.37		21.26
1980	130.40		17.89		20.71
1981	133.92	24.33	18.17	28.0	20.91
1982	137.54		17.69		20.36
1983	141.25		17.22		19.82
1984	145.07		16.77		19.30
1985	148.98		16.33		18.79

* 1961-1968 extrapolated from Wholesale Price Index; 1957-1959=100; 1969-1971 inflationary factors reported in N.I.C.B., 1972-1985 estimated using 1965-1970 average inflationary rate of 2.7 percent per year.

† Initial appraisal assumptions for New Gas with 1¢/MCF increase at 5-year intervals.

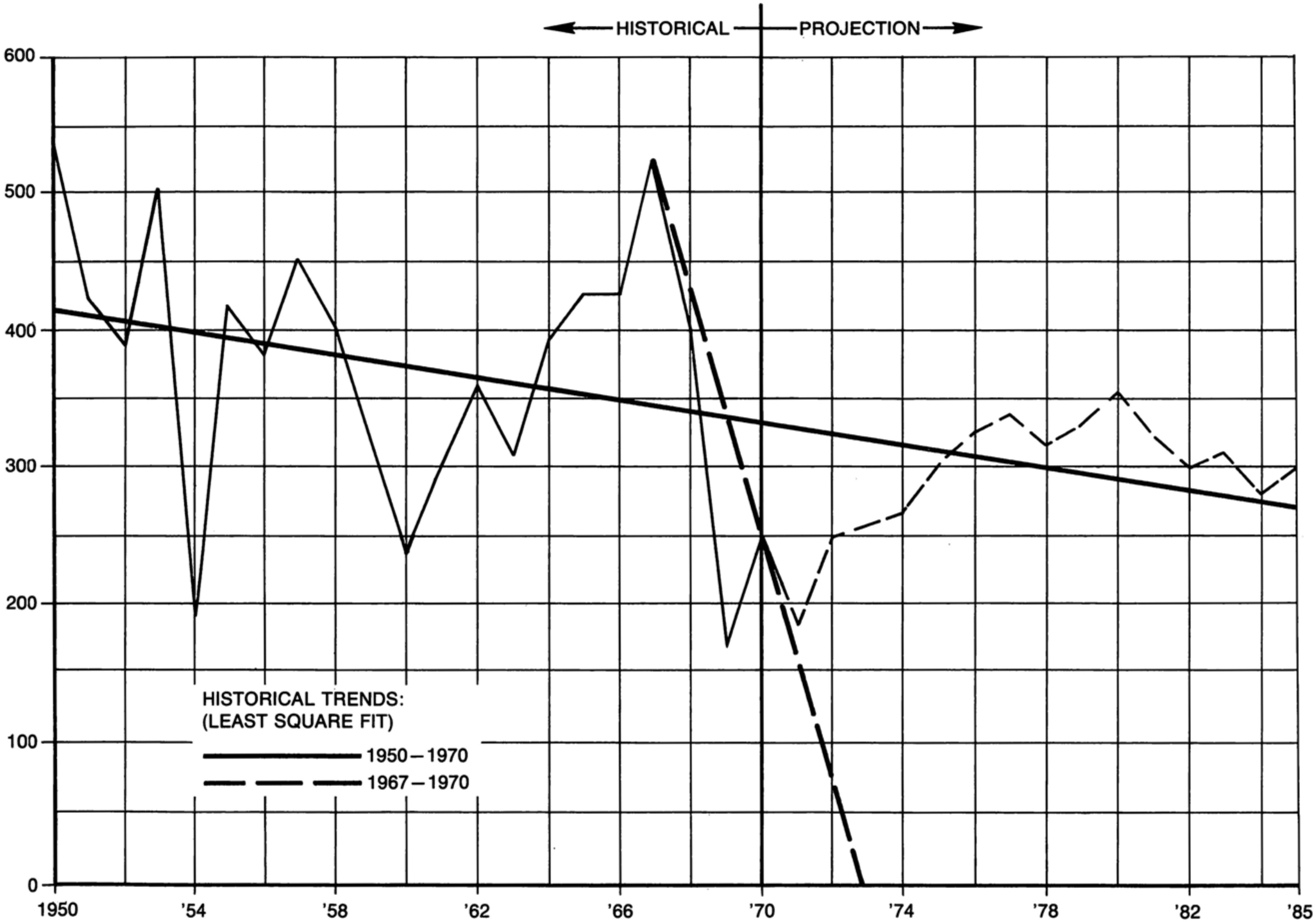


Figure 11. Nonassociated Gas Reserves Added per Foot of Hole Drilled
(Productive Wells Plus Dry Hole--Gas Wells).

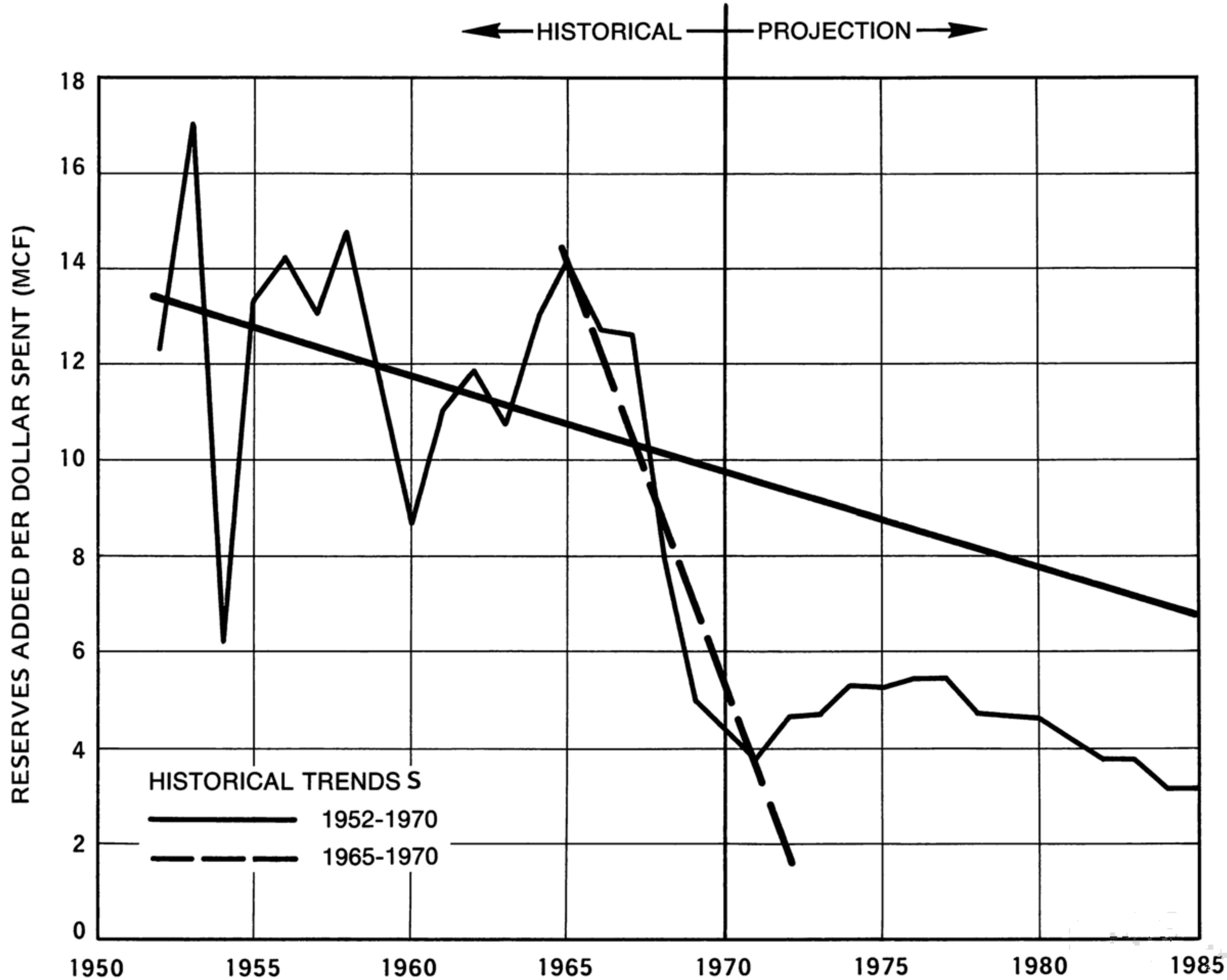


Figure 12. Nonassociated Gas Reserve per Dollar Spent (MCF).

to greater depths in certain geological provinces, drilling in more expensive operating areas such as offshore and finding smaller volumes of gas per foot drilled.

The projection by the Gas Supply Task Group contains a leveling out of the most recent experience but does reflect a continued modest decline because real costs are expected to continue to rise. The expectation of increased activity in the more hostile environments and, therefore, essentially more expensive areas of future drilling activity will be a major influence.

Table LXII shows relative cost comparisons between current onshore drilling expenditures and offshore and Alaskan costs. Offshore costs are four to five times as great, and Alaskan wells are some six to twelve times as costly as inland wells.

The need to emphasize deeper offshore and Alaskan drilling is supported by the interpretive work reflected in Figures 13 and 14. These illustrations show that more than 60 percent of the next 320 TCF of gas reserve additions will most likely be found at depths below 15,000 feet, and approximately 50 percent of those reserves will be located offshore and in Alaska.

The capital requirements analytical forecast shown in Table LXIII contains exploration and development expenditures and nonassociated gas reserve additions per dollar expended. It is an extrapolation from historical data, which reflected primarily shallower onshore activity, and is therefore regarded as conservative.

The factors discussed above which produced the foregoing data support the construction of Table LXIV, which reflects gross annual revenues expected from wellhead sales. These revenues are shown to decrease more than 22 percent from 1971 to 1985 as gross wellhead production declines over 41 percent. Condensate production volumes, projected on the basis of natural gas production, are also shown with the revenues expected to be derived therefrom. Total revenue from natural gas and condensate sales declines over 25 percent. These economic circumstances require the reinvestment of a rather dramatically increasing proportion of the proceeds from production to sustain the exploration and development drilling effort that supports the nonassociated gas reserve addition projection. As reflected in the report of the Joint Oil and Gas Capital Requirements Task Group, an increase in reinvestment of net proceeds from production from 67 percent in 1970 to 82 percent in 1985 is required.

Actual gas well footage projected to be drilled during the 1971-1985 period is shown in Figure 15, which also contains historical data from the 1950-1970 period. Without the assumed wellhead price increase for regulated gas production, revenues would have diminished even further, and drilling effort and nonassociated gas reserve additions would have been projected to decline even further--or the percentage of reinvestment would have to reach improbable levels to achieve the results herein projected.

Recognition must be given to the fact that the intrastate gas market accounts for a significant portion of Texas and Louisiana production and has not been subject to wellhead price regulation. However, the increasing price trend in that segment of the market alone has not been able to offset declines in the number of wells drilled in those states. In 1970, the number of wells drilled in the State of Texas (7,962) was 16 percent below the number drilled in 1969. Similarly, drilling in the State of Louisiana in 1970 resulted in 2,792 wells, a decline of 23 percent from the previous year.

Part of this decline can be attributed to general economic conditions and, in particular, to the effects of the Tax Reform Act of 1969 on the petroleum industry. Considering that intrastate wellhead prices currently range from 5¢ to 12¢ per MCF higher than the regulated interstate wellhead prices, it appears that a significant increase in natural gas exploration and development activity will result only if the economic incentives to the total industry drilling effort for oil and gas can be substantially improved.

TABLE LXII

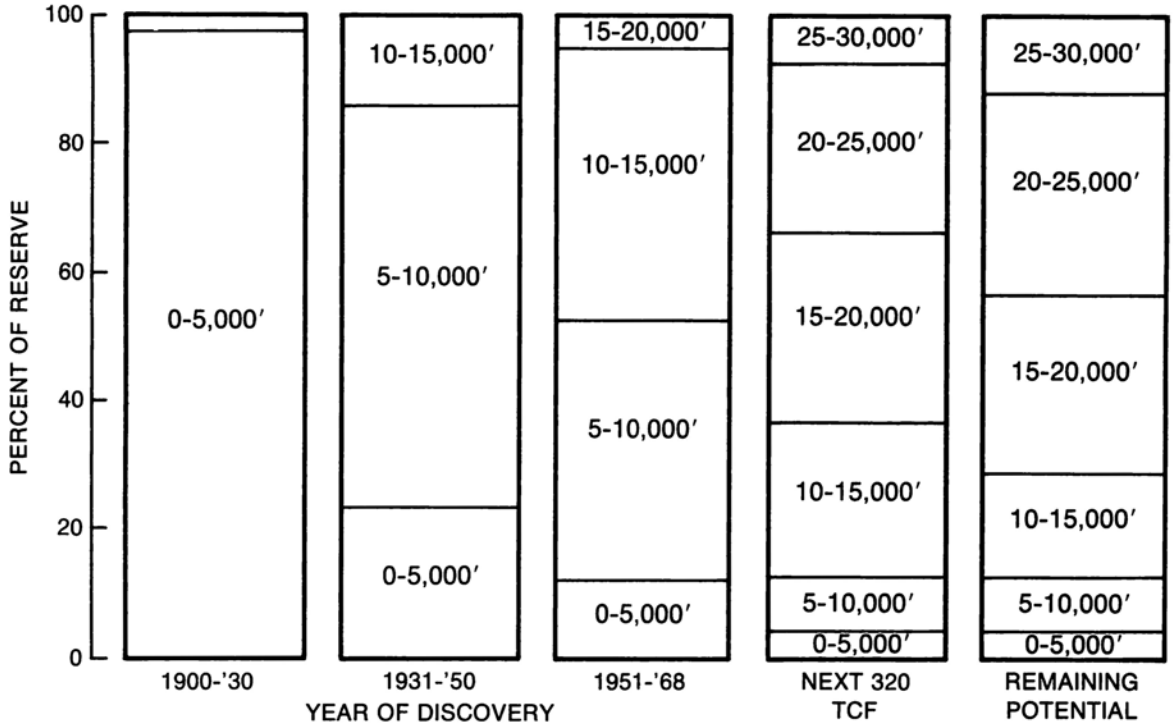
AVERAGE COST AND DEPTH OF GAS WELLS BY LOCATION

	Total U.S.	Total Offshore (Ex Alaska)	Total Alaska Onshore & Offshore
Av. Cost/Foot ($)			
1966	21.75	55.25	125.83
1967	23.05	51.45	85.12
1968	24.05	53.38	142.64
1969	25.58	67.57	216.17
Av. Cost/Well ($000)			
1966	134	664	1,120
1967	141	594	917
1968	149	595	1,112
1969	154	748	1,932
Av. Depth/Well (Feet)			
1966	6,151	12,033	8,899
1967	6,116	11,547	10,773
1968	6,177	11,149	7,794
1969	6,034	11,071	8,936

COSTS AND DEPTHS AT OFFSHORE AND ALASKAN LOCATIONS AS MULTIPLES OF TOTAL U.S. AVERAGES

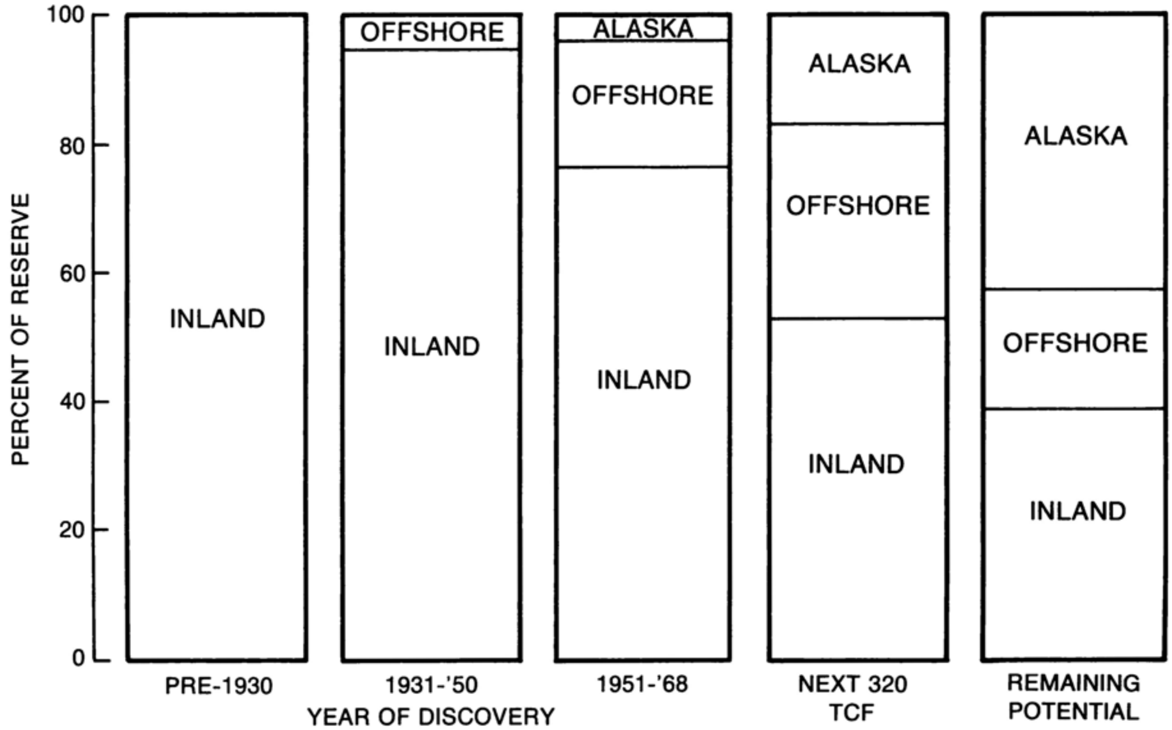
Av. Cost/Foot			
1966	1.0	2.5	5.8
1967	1.0	2.2	3.7
1968	1.0	2.2	5.9
1969	1.0	2.6	8.5
Av. Cost/Well			
1966	1.0	5.0	8.4
1967	1.0	4.2	6.5
1968	1.0	4.0	7.5
1969	1.0	4.9	12.5
Av. Depth/Well			
1966	1.0	2.0	1.4
1967	1.0	1.9	1.8
1968	1.0	1.8	1.3
1969	1.0	1.8	1.5

Source: *Joint Association Survey of the Oil and Gas Producing Industry*, Sponsored by the American Petroleum Association, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).



Source: *Prospects for Increased Gas Supply*, paper presented by Ralph Garret, Humble Oil & Refining Co., before the New England Gas Association Annual Business Conference, March 19, 1971.

Figure 13. Depth Distribution of Nonassociated Gas Discoveries Inland (Excluding Alaska).



Source: *Prospects for Increased Gas Supply*, paper presented by Ralph Garret, Humble Oil & Refining Co., before the New England Gas Association Annual Business Conference, March 19, 1971.

Figure 14. Geographic Distribution of Nonassociated Gas Discoveries.

TABLE LXIII

EXPLORATION AND DEVELOPMENT COSTS
NONASSOCIATED GAS--LOWER 48 STATES

	Offshore (Millions of Dollars)			Onshore (Millions of Dollars)					
Year	Offshore Bonus	Exploration and Development	Total	Bonus	Exploration and Development	Total	Grand Total	Nonassoc. Reserve Adds (TCF)	MCF/$ Expended
1971	305	290	595	86	1,141	1,227	1,822	6.80	3.73
1972	327	300	627	89	1,110	1,199	1,826	8.68	4.75
1973	349	307	656	91	1,080	1,171	1,827	8.70	4.76
1974	371	315	686	94	1,052	1,146	1,832	9.72	5.31
1975	393	322	715	97	1,024	1,121	1,836	9.62	5.24
71-75	1,745	1,534	3,279	457	5,407	5,864	9,143	43.52	
1976	415	328	743	100	996	1,096	1,839	9.87	5.37
1977	437	334	771	102	969	1,071	1,842	9.87	5.36
1978	459	340	799	105	943	1,048	1,847	8.88	4.81
1979	481	345	826	108	918	1,026	1,852	8.87	4.79
1980	503	349	852	110	894	1,004	1,856	8.85	4.77
76-80	2,295	1,696	3,991	525	4,720	5,245	9,236	46.34	
1981	525	353	878	113	870	983	1,861	7.98	4.29
1982	547	356	903	116	847	963	1,866	6.97	3.74
1983	569	359	928	119	824	943	1,871	6.97	3.73
1984	591	362	953	121	802	923	1,876	5.97	3.18
1985	613	365	978	124	780	904	1,882	5.97	3.17
81-85	2,845	1,795	4,640	593	4,123	4,716	9,356	33.86	
71-85	6,885	5,025	11,910	1,575	14,250	15,825	27,735		

TABLE LXIV

GAS AND CONDENSATE REVENUE

Year	Gas Sales Revenue: Gross Prod.	Gas Sales Revenue: Net Prod.	Gas Sales Revenue: Av. Price	Gas Sales Revenue: Revenue Mil. $	Condensate Revenue: Prod. MM Bbls.	Condensate Revenue: $/Bbl	Condensate Revenue: Revenue Mil. $	Total Gas & Condensate Revenue Mil. $
1971	22.28	20.05	16.7	3,348	151	3.85	581	3,929
1972	22.26	20.03	17.1	3,425	151	3.85	581	4,006
1973	21.46	19.31	17.4	3,360	151	3.85	581	3,941
1974	20.60	18.54	17.7	3,282	151	3.85	581	3,863
1975	19.83	17.85	17.9	3,195	151	3.85	581	3,776
71-75	106.43	95.78		16,610	755		2,905	19,515
1976	19.11	17.20	19.2	3,302	124	3.85	477	3,779
1977	18.37	16.53	19.5	3,223	124	3.85	477	3,700
1978	17.61	15.85	19.7	3,122	124	3.85	477	3,599
1979	16.92	15.23	20.0	3,046	124	3.85	477	3,523
1980	16.29	14.66	20.2	2,961	124	3.85	477	3,438
76-80	88.30	79.47		15,654	620		2,385	18,039
1981	15.63	14.07	21.4	3,011	87	3.85	335	3,346
1982	14.93	13.44	21.5	2,890	87	3.85	335	3,225
1983	14.31	12.88	21.7	2,795	87	3.85	335	3,130
1984	13.63	12.27	21.9	2,687	87	3.85	335	3,022
1985	13.04	11.74	22.1	2,595	87	3.85	335	2,930
81-85	71.54	64.40		13,978	435		1,675	15,653
71-85	266.27	239.65		46,242	1,810		6,965	53,207

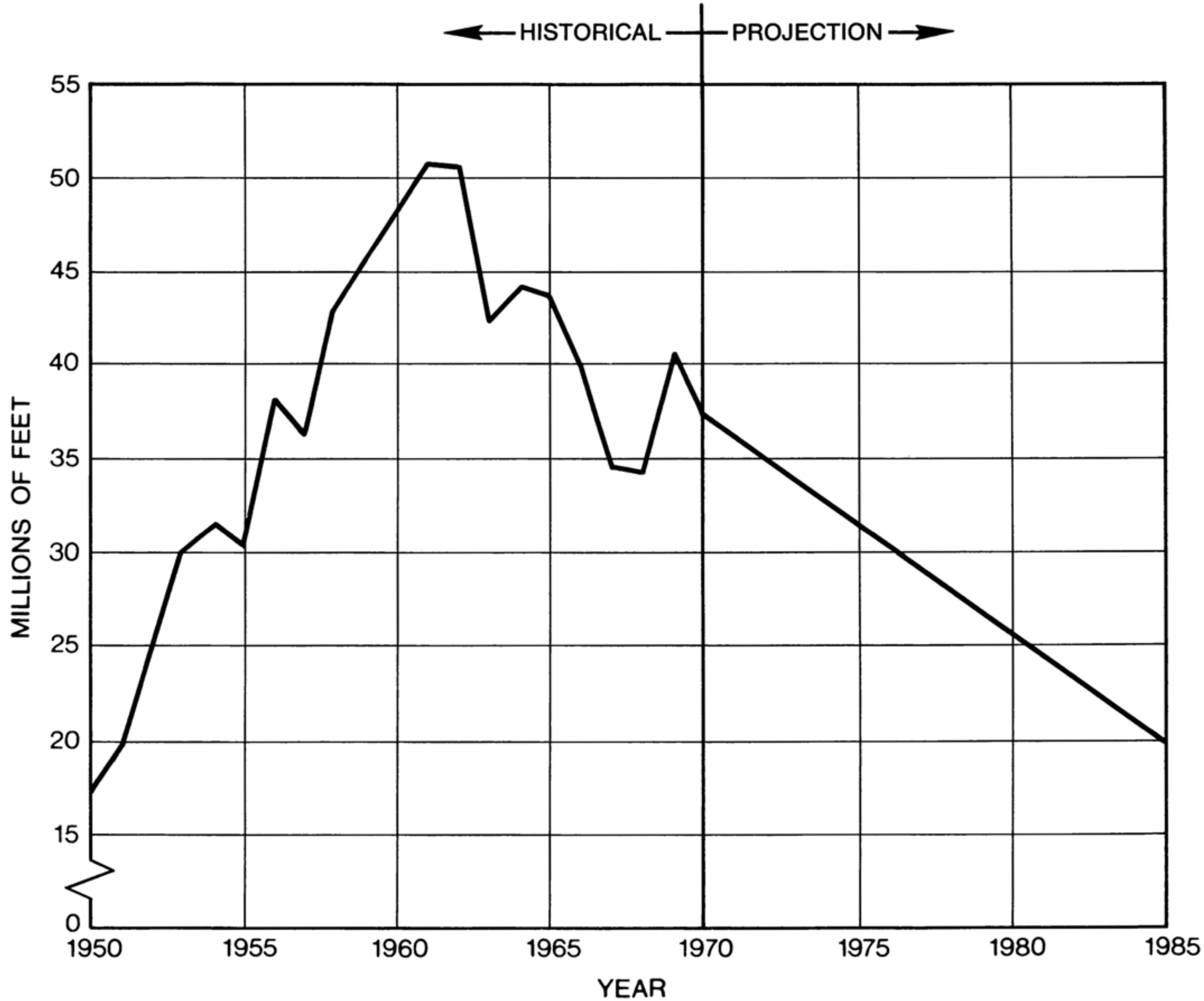


Figure 15. Total Footage of Hole Drilled (Productive Wells Plus Dry Hole--Gas Wells).

4. Gas Supply--Other Forms and Sources

Pipeline imports into the lower 48 states will, during the early phase of the study period, be supplied by Canadian production. The increase reflected on Table LV (p. 81) is gradual and reflects the most recent export authorizations by the National Energy Board of Canada. The policy enunciated by this Canadian agency is that exports will be permitted of only those volumes of proved reserves in excess of those necessary to maintain an R/P ratio of 30. This standard will require an exceptional level of reserve adds in the future to significantly increase exports.

Imports from Mexico have never represented a significant share of U.S. supply and are expected to be terminated before 1980, as discussed in the Assumptions (see pp. 78-80).

The Alaskan North Slope region holds great potential for the purpose of supplementing supply to the lower 48 states. However, this area's reserve additions of 26 TCF reported in 1970 are exclusively associated and dissolved gas. To date, environmental concerns have prevented initiating any such facilities. No gas transmission pipeline project can be finalized until contracts can be negotiated for an assured and adequate volume of production on a daily basis. Absent an assured market outlet, little if any exploration for gas can be contemplated, and construction of a natural gas pipeline cannot be anticipated prior to the 1976-1977 period. As a result, pipeline imports from the North Slope of Alaska of 1.07 TCF per year are first projected in 1977, increasing to only 1.5 TCF per year in 1985.

Projections of future supplies of gas plant liquids and condensate are discussed in the Assumptions (see p. 79) and are based on historical data which establish relationships between volumes of natural gas produced and processed.

Actual volumes, by key years, are shown in Table LXV.

TABLE LXV

GAS PLANT LIQUID AND CONDENSATE PRODUCTION

	1970	1975	1980	1985
Gas Plant Liquid Production				
Millions of Barrels	613.0	558.0	475.0	342.0
Millions of B/D	1.7	1.5	1.3	1.0
Condensate Production				
Millions of Barrels	134.0	140.0	121.0	89.0
Millions of B/D	0.4	0.4	0.3	0.2

Imports of liquefied petroleum gas--butane, propane and mixtures--are specifically identified in Table LV. The following Table LXVI reflects key year expectations on the basis of the particular assumptions described in this report (pp. 78-80).

TABLE LXVI

LPG--BUTANE, PROPANE AND MIXTURES
(Thousands of Barrels)

	1970*	1975	1980	1985
Imports	19,160	46,000	130,000	240,000
Exports	9,650	2,000	---	---
NET	9,510	44,000	130,000	240,000

* Source: Bureau of Mines.

Liquefied natural gas imports will become an increasingly significant contribution to gas supply. In terms of BTU equivalent, it is expected to multiply more than 20-fold from 1975 to 1985. As reflected in the Gas Transportation Task Group Report, this is a capital intensive enterprise requiring an investment of almost $11 billion by 1985. Because of this fact, each particular import project will represent a significant increment to supply, as discussed in the Assumptions (see pp. 78-80). By 1985, LNG imports should represent almost 20 percent of the gas supply of the United States projected in this initial appraisal.

Synthetic gas of pipeline quality can be manufactured from coal through a process of gasification or from petroleum products through a process of reforming.

The manufacture of gas from reformed petroleum products is receiving much attention in the United States because of the current supply situation. Generally, plants capable of reforming petroleum products will be constructed in modules of 125-MCF output per day with product input of 25 MB/D. With the cost of petroleum products estimated at 6¢ to 9¢ per gallon, gas costs would range from about 76¢ to $1.03 per MCF. Total output from these plants will probably be restricted by the availability of raw material with current industry estimates setting supply at 200,000 barrels. It was this figure that the task group used in projecting one billion cubic feet per day of reformed gas output by 1975. This level of production was not increased for future years because of the restrictions in raw material availability.

The coal gasification process and attendant costs are discussed in Chapter Nine herein on coal.

Processes other than the Lurgi process which may be potentially more efficient and produce somewhat less expensive pipeline quality gas cannot be expected to reach economically scaled proportions before 1980 at present development rates. Therefore, the supplemental volumes of synthetic gas reflected in Table LV (p. 81), at a capital cost of $2.5 billion, represent only the construction of those facilities considered necessary in the operation of particular existing pipeline transmission facilities.

Chapter Seven

Gas Task Group

Gas Demand

GAS DEMAND TASK GROUP

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GAS DEMAND TASK GROUP REPORT

ABSTRACT

Under the conditions assumed for the initial appraisal, gas consumption will be severely restricted by supply conditions. However, the mission of the Gas Demand Task Group was to project demand as it appeared likely to develop, absent supply limitations, so that this chapter addresses what may be characterized as *potential* demand. This potential demand, when measured against the gas supply projection contained in the preceding chapter, results in the following comparison:

Gas Supply/Demand Comparison
(Trillions of BTU's)

	1975	1980	1985
Potential Demand	30,268	34,700	40,119
Anticipated Supply	22,420	22,480	22,180
Indicated Shortfall	7,848	12,220	17,939

Natural gas requirements amounted to an estimated 36.7 percent of the total energy consumption of the United States in 1970. This share is projected to remain relatively stable at 36.3 percent in 1975 but then decline to 33.8 percent in 1980 and 32.1 percent in 1985. These market shares are based on the total primary energy consumption forecast developed by the Energy Demand Task Group shown in Table LXVII. The total gas requirements include "field use." Because of reporting discrepancies in energy supply and requirements, however, these relative shares of total energy needs must be viewed with great care.

Total requirements are expected to rise from 24.9 quadrillion BTU's in 1970 to 40.1 in 1985. This would be an increase of about 61 percent. Table LXVII summarizes the projected quantities of gas consumption for 1970, 1975, 1980 and 1985 by use category and shows the average annual percentage changes at 5-year intervals and over the 15-year period. General growth, although at generally declining rates, is expected to continue in all categories except the "raw material and other" category. Its decline is due entirely to a drop in estimated field use. The average annual compound growth rate for total needs in the 15-year period would be 3.2 percent. Industrial use exhibits the greatest 15-year increase, rising nearly 8 quadrillion BTU's by 1985.

The data for projected gas requirements were derived from 1969 projections compiled by the Future Requirements Committee. These data reflect no consideration of gas supply limitations or relative changes in the energy pricing structure.

SUMMARY OF GAS DEMAND TASK GROUP REPORT

This report largely is based on data developed and compiled by the Future Requirements Committee under the auspices of the Gas Industry Committee. Actual data on gas requirements in the United States for the years 1964 through

TABLE LXVII

SUMMARY OF TOTAL UNITED STATES GAS REQUIREMENTS AND PRIMARY ENERGY FORECASTS

		Gas Requirements* (BTU x 10^{12})				Annual Compound Rate of Change - Percent			
		1970	Projected						
Market	Use Category	Prelim. Act.	1975	1980	1985	1970-75	1975-80	1980-85	1970-85
Gas Requirements*	Residential and Commercial	7,218	8,426	9,930	11,661	3.1	3.3	3.3	3.2
	Industrial	8,862	11,375	13,700	16,467	5.1	3.8	3.7	4.2
	Electric Utility	4,049	4,829	5,517	6,412	3.6	2.7	3.1	3.1
	Transportation	629	847	1,025	1,180	6.1	3.9	2.9	4.3
	Raw Material and Other	4,110	4,791	4,528	4,399	3.1	-1.1	-0.6	0.5
	TOTAL	24,868	30,268	34,700	40,119	4.0	2.8	3.0	3.2
Primary Energy Consumption†	Residential and Commercial	12,994	14,733	16,669	18,768	2.6	2.5	2.4	2.5
	Industrial	17,798	20,039	22,341	24,667	2.4	2.2	2.0	2.2
	Electric Utility	16,695	23,525	32,996	44,363	7.1	7.0	6.1	6.7
	Transportation	16,282	19,905	23,870	28,214	4.1	3.7	3.4	3.7
	Raw Material and Other	4,058	5,279	6,705	8,930	5.4	4.9	5.9	5.4
	TOTAL	67,827	83,481	102,581	124,942	4.2	4.2	4.0	4.1

* Gas Demand Task Group, May 11, 1971.
† Energy Demand Task Group, April 2, 1971.

1968; estimated data for 1969 through 1971; and projected data for 1975, 1980, 1985 and 1990 are contained in Volume No. 3 of *Future Natural Gas Requirements of the United States*, published by the Future Requirements Agency, Denver Research Institute, University of Denver, Colorado, in September 1969. The *Supplement to Volume No. 3, Future Natural Gas Requirements of the United States*, published by the Future Requirements Agency in December 1970, revises the original estimate of gas requirements for 1969 to an actual basis and provides revised 1968 actual volumes. A summary of the gas requirements and comparison with total United States primary energy consumption is shown in Table LXVII.

The methodology employed by the Future Requirements Committee in the assembly and projection of these data is described in considerable detail in Volume No. 3. It is referred to here only to the extent necessary to interpret the findings of the Gas Demand Task Group. Various source documents and basic data are also referred to in the footnotes contained in Table LXVIII for certain of the PAD Districts. These footnotes generally are applicable to all of the Districts, since the same methodology was used to derive these data.

In brief, the Gas Demand Task Group, after a survey of available information, agreed to use the Future Requirements Committee data as its primary source. However, these data were not in a form suitable for use in the National Petroleum Council study.

First, the data had to be rearranged from the state projections developed by the Future Requirements Committee into projections for the PAD Districts. A map showing the PAD Districts and Census Divisions appears in the front of this volume. In addition to grouping the actual and projected gas requirements into the five basic Districts, breakdowns of PAD District I into the New England, Middle Atlantic and South Atlantic Census Divisions, and of PAD District II into the East North Central Census Division and a section covering the remainder of District II, were required. Further, it was necessary to modify the classes of gas requirements reported by the Future Requirements Committee to conform to the use categories required in the National Petroleum Council study. These respective categories were as follows:

Future Requirements Committee	National Petroleum Council
Firm Residential	Residential and Commercial
Firm Commercial	Industrial
Firm Industrial	Transportation
Interruptible	Electric Utilities
Other	Raw Material and Other
Field Use	

All of the Future Requirements Committee classes were reported for individual states except for field use. Thus, to regroup the data published by the Future Requirements Committee into PAD Districts, it was necessary to develop an independent breakdown of the total national field use reported by the Future Requirements Committee.

The following procedure was used to regroup the Future Requirements Committee data into the categories employed in the National Petroleum Council study:

1. "Firm residential" plus "firm commercial" were equated to "residential and commercial."

TABLE LXVIII

ACTUAL AND PROJECTED ANNUAL AND CUMULATIVE GAS REQUIREMENTS BY USE CATEGORY AND PAD DISTRICTS FOR SELECTED YEARS 1965 THRU 1985

(BTU x 10^{12})

Year	Use Category	PAD I* New England	PAD I* Middle Atlantic	PAD I* South Atlantic	PAD I* Total	PAD II† East North Central	PAD II† All Other	PAD II† Total	PAD 3	PAD 4	PAD 5‡	Total United States
1965	Residential/Commercial	130	868	379	1,377	1,597	916	2,513	526	208	773	5,397
	Industrial	30	452	428	910	1,030	717	1,747	2,595	177	657	6,086
	Electric Utilities	14	102	120	236	69	456	525	1,040	36	586	2,423
	Transportation	3	26	17	46	104	78	182	198	8	44	478
	Raw Material & Other	8	70	85	163	156	320	476	1,967	83	266	2,955
	TOTAL	185	1,518	1,029	2,732	2,956	2,487	5,443	6,326	512	2,326	17,339
1969	Residential/Commercial	167	1,079	514	1,760	2,089	1,039	3,128	709	249	927	6,773
	Industrial	53	572	587	1,212	1,420	934	2,354	3,576	233	856	8,231
	Electric Utilities	7	167	274	448	170	638	808	1,593	48	721	3,618
	Transportation	4	33	25	62	133	106	239	274	10	25	610
	Raw Material & Other	8	91	89	188	258	518	776	2,606	117	283	3,970
	TOTAL	239	1,942	1,489	3,670	4,070	3,235	7,305	8,758	657	2,812	23,202
1970§	Residential/Commercial	190	1,136	551	1,877	2,197	1,152	3,349	715	260	1,017	7,218
	Industrial	63	633	607	1,303	1,566	960	2,526	3,832	240	961	8,862
	Electric Utilities	7	212	329	548	194	669	863	1,732	49	857	4,049
	Transportation	4	32	25	61	131	102	233	271	9	55	629
	Raw Material & Other	10	104	133	247	307	555	862	2,624	128	249	4,110
	TOTAL	274	2,117	1,645	4,036	4,395	3,438	7,833	9,174	686	3,139	24,868
1971	Residential/Commercial	193	1,133	555	1,881	2,203	1,137	3,340	708	260	1,008	7,197
	Industrial	65	664	645	1,374	1,658	979	2,637	4,090	248	1,012	9,361
	Electric Utilities	7	221	347	575	205	680	885	1,838	51	873	4,222
	Transportation	5	39	25	69	149	115	264	313	10	63	719
	Raw Material & Other	9	104	127	240	316	583	899	2,804	134	231	4,308
	TOTAL	279	2,161	1,699	4,139	4,531	3,494	8,025	9,753	703	3,187	25,807
1972	Residential/Commercial	205	1,179	594	1,978	2,302	1,174	3,476	730	264	1,052	7,500
	Industrial	70	714	718	1,502	1,751	1,013	2,764	4,266	255	1,066	9,853
	Electric Utilities	7	210	344	561	216	704	920	1,917	52	917	4,367
	Transportation	5	38	30	73	156	119	275	326	11	66	751
	Raw Material & Other	10	108	130	248	336	600	936	2,870	137	237	4,428
	TOTAL	297	2,249	1,816	4,362	4,761	3,610	8,371	10,109	719	3,338	26,899
1973	Residential/Commercial	216	1,226	632	2,074	2,402	1,211	3,613	753	272	1,097	7,809
	Industrial	77	763	790	1,630	1,844	1,047	2,891	4,450	262	1,120	10,353
	Electric Utilities	6	200	341	547	227	728	955	1,999	54	961	4,516
	Transportation	5	39	33	77	164	122	286	340	11	69	783
	Raw Material & Other	10	111	133	254	355	616	971	2,955	141	231	4,552
	TOTAL	314	2,339	1,929	4,582	4,992	3,724	8,716	10,497	740	3,478	28,013
1974	Residential/Commercial	228	1,273	671	2,172	2,502	1,248	3,750	776	279	1,142	8,119
	Industrial	82	812	862	1,756	1,938	1,080	3,018	4,642	270	1,174	10,860
	Electric Utilities	6	190	338	534	239	751	990	2,085	50	1,005	4,664
	Transportation	6	41	34	81	171	126	297	354	11	72	815
	Raw Material & Other	10	115	137	262	374	630	1,004	3,034	145	226	4,671
	TOTAL	332	2,431	2,042	4,805	5,224	3,835	9,059	10,891	755	3,619	29,129
1975	Residential/Commercial	239	1,319	710	2,268	2,602	1,285	3,887	800	285	1,186	8,426
	Industrial	88	861	934	1,883	2,032	1,114	3,146	4,842	277	1,227	11,375
	Electric Utilities	6	180	335	521	251	774	1,025	2,176	57	1,050	4,829
	Transportation	6	42	36	84	179	129	308	369	11	75	847
	Raw Material & Other	10	118	141	269	392	641	1,033	3,117	149	223	4,791
	TOTAL	349	2,520	2,156	5,025	5,456	3,943	9,399	11,304	779	3,761	30,268
1971	Residential/Commercial	1,081	6,130	3,162	10,373	12,011	6,055	18,066	3,767	1,360	5,485	39,051
Thru	Industrial	382	3,814	3,949	8,145	9,223	5,233	14,456	22,290	1,312	5,599	51,802
1975	Electric Utilities	32	1,001	1,705	2,738	1,138	3,637	4,775	10,015	264	4,806	22,598
	Transportation	27	199	158	384	819	611	1,430	1,702	54	345	3,915
	Raw Material & Other	49	556	668	1,273	1,773	3,070	4,843	14,780	706	1,148	22,750
	TOTAL	1,571	11,700	9,642	22,913	24,964	18,606	43,570	52,554	3,696	17,383	140,116
1980	Residential/Commercial	300	1,544	895	2,739	3,074	1,465	4,539	920	323	1,409	9,930
	Industrial	109	996	1,224	2,329	2,549	1,297	3,846	5,722	330	1,473	13,700
	Electric Utilities	6	180	335	521	315	901	1,216	2,571	68	1,141	5,517
	Transportation	7	49	45	101	217	148	365	460	13	86	1,025
	Raw Material & Other	12	132	159	303	368	635	1,003	2,862	151	209	4,528
	TOTAL	434	2,901	2,658	5,993	6,523	4,446	10,969	12,535	885	4,318	34,700
1976	Residential/Commercial	1,078	5,726	3,210	10,014	11,352	5,500	16,852	3,440	1,216	5,190	36,712
Thru	Industrial	394	3,714	4,316	8,424	9,162	4,822	13,984	21,068	1,214	5,400	50,090
1980	Electric Utilities	24	720	1,340	2,084	1,132	3,350	4,482	9,494	250	4,382	20,692
	Transportation	26	182	162	370	792	554	1,346	1,658	48	322	3,744
	Raw Material & Other	44	500	600	1,144	1,520	2,552	4,072	11,958	600	864	18,638
	TOTAL	1,566	10,842	9,628	22,036	23,958	16,778	40,736	47,618	3,328	16,158	129,876
1985	Residential/Commercial	371	1,788	1,113	3,272	3,668	1,656	5,324	1,060	363	1,642	11,661
	Industrial	136	1,139	1,609	2,884	3,182	1,531	4,713	6,765	386	1,719	16,467
	Electric Utilities	6	180	335	521	393	1,064	1,457	3,040	79	1,315	6,412
	Transportation	9	56	55	120	265	170	435	510	15	100	1,180
	Raw Material & Other	13	147	181	341	363	630	993	2,714	150	201	4,399
	TOTAL	535	3,310	3,293	7,138	7,871	5,051	12,922	14,089	993	4,977	40,119
1981	Residential/Commercial	1,342	6,664	4,016	12,022	13,484	6,242	19,726	3,960	1,372	6,102	43,182
Thru	Industrial	490	4,270	5,666	10,426	11,462	5,656	17,118	24,974	1,432	6,384	60,334
1985	Electric Utilities	24	720	1,340	2,084	1,416	3,930	5,346	11,222	294	4,912	23,858
	Transportation	32	210	200	442	964	636	1,600	1,940	56	372	4,410
	Raw Material & Other	50	558	680	1,288	1,462	2,530	3,992	11,152	602	820	17,854
	TOTAL	1,938	12,422	11,902	26,262	28,788	18,994	47,782	53,248	3,766	18,590	149,638

* 1965, 1971, 1975, 1980 and 1985 data as reported by Future Requirements Committee in Volume No. 3, September 1969; 1969 data reported by Future Requirements Committee in December 1970; 1972, 1973 and 1974 data were interpolated on a linear basis between data cited for 1971 and 1957; "electric utilities" requirements based on 1965-1969 trend of share of "electric utilities" of the sum of Future Requirements Committee figures for "firm industrial" plus "interruptible"; 1970 and 1971 based on the weighted percent share of electric power for each region; 1980 and 1985 assumed to remain unchanged volumetrically from 1975; 1972 through 1975 based on a weighted decline from each year for the separate Census Divisions using data reported in National Coal Policy Conference Letter dated February 18, 1971, reporting information compiled by the Federal Power Commission. This share was as follows:

Subregion	1970-1971 Share	% of Prior Year Starting in 1972
New England	10%	95%
Middle Atlantic	20%	95%
South Atlantic	35%	99%

The 1980 and 1985 figures were assumed to remain unchanged volumetrically from 1975.

† "Electric utilities" requirements assumed to be 11 percent of combined Future Requirements Committee "industrial" and "interruptible" figures in East North Central subregion and 41 percent in remaining portion of PAD District 2.

‡ "Electric utilities" use is included in "industrial" in the 1969 Future Requirements Committee report. This item will be segregated in the 1971 Future Requirements Committee report. For purposes of this report, the segregation for the State of California was made from supplemental data available. For all other states, the allocation to "electric utilities" is based on the 5-year average 1965-1969.

§ Based on Future Requirements Committee 1969 Report No. 3 for all use categories; preliminary actual data developed from 1970 Bureau of Mines provisional estimates of 1970 actual data but corrected to each use category using the ratio of 1969 actual Future Requirements Committee data to 1969 actual Bureau of Mines information of 22546.1 x 10^{12} BTU plus 3082 x 10^{12} BTU for "field use." These ratios were:

Category	1969 FRC Ratio to 1969 BM Data
Residential/Commercial	0.982
Industrial	0.937
Electric Utilities	1.006
Transportation	0.937
Raw Material & Other	0.986

2. "Firm industrial" plus "interruptible" were equated to "industrial" plus "electric utilities." Each member of the Gas Demand Task Group reporting on a given PAD District then had the responsibility for estimating the portion of "firm industrial" plus "interruptible" corresponding to "electric utility" use. The methodology is given in appropriate footnotes to the tables in this chapter.

3. The "transportation" category required for the National Petroleum Council study was estimated from 1969 data reported by the Bureau of Mines on the use of gas for transportation (primarily pipeline compressor station fuel). The use for this purpose for each PAD District computed as a percentage of the total gas requirements, exclusive of field use, is as follows: PAD I, 1.7 percent; PAD II, 3.5 percent; PAD III, 4.3 percent; PAD IV, 1.7 percent; and PAD V, 2.1 percent. Within Districts I and II these amounts were allocated to the appropriate subregions. It was assumed that these percentages remained constant through 1985.

4. The quantities of gas in the "residential and commercial," "industrial," "electric utilities" and "transportation" categories were then subtracted from the total requirements, excluding "field use," for each PAD District computed from the Future Requirements Committee data. The remaining gas requirements were identified as "raw material and other, excluding field use." For consistency with other task group reports, only the "raw material and other" category is shown here, which includes "field use." The national total for "field use" gas incorporated in these numbers is as follows:

Year	BTU x 10^{12}
1970	3,082
1975	3,653
1980	3,317
1985	3,046

The recomputed data derived from the Future Requirements Committee data are shown in Table LXVIII. All data are reported in units of trillions (10^{12}) of BTU's. One trillion BTU's is the equivalent of one billion cubic feet of natural gas having a heating value of 1,000 BTU/CF. "Field use" requirements were reported in units of billions of cubic feet of unspecified heating value. To simplify reporting the results, no allowance for this discrepancy from 1,000 BTU/CF was made.

Table LXVIII shows a summary of gas requirements by PAD Districts, broken down in accordance with the National Petroleum Council categories. The Future Requirements Committee subcategory "field use" is incorporated with the National Petroleum Council use category, "raw materials and other."

Tables LXIX through LXXIV show the computations and resulting data for breakdown into PAD Districts of total U.S. "field use" data reported by the Future Requirements Committee. The National Petroleum Council category "raw material and other" approximately corresponds to the Future Requirements Committee category "other," plus "field use," as will be discussed below.

Differences in the methods of reporting production and consumption data by the several government agencies and industrial organization sources result in numberical discrepancies which cannot be fully reconciled. These differences are relatively minor when compared to the quantities of energy involved, and an unsupported forced reconciliation therefore has been considered inappropriate at this time. Some of this discrepancy results from the lack of precise equivalents for such frequently used terminology as "requirements," "consumption," "sales" and "demand." The total gas requirements developed by the Future Requirements Committee include field use.

TABLE LXIX

UNITED STATES TOTAL MISCELLANEOUS NATURAL GAS VOLUMES

	CF x 10^9 & BTU x 10^{12}				Gas Plant Shrinkage	
Year	Used at Leases A	Vented at Leases B	Gas Plant Fuel & Losses C	Used to Mfg. Chemicals D	BCF E	BTUx10^{12} F
1965 (actual)	683	319	512	404	754	1,992
1969 (actual)	763	526	679	553	867	2,264
1970 (prelim.)	876	565	736	570	956	2,485
1971 (estimate)	948	572	768	605	1,017	2,639
1972 (estimate)	981	581	774	630	1,059	2,730
1973 (estimate)	1,055	583	776	663	1,071	2,752
1974 (estimate)	1,109	569	785	695	1,107	2,828
1975 (estimate)	1,158	559	794	767	1,142	2,908
1980 (estimate)	1,069	490	686	1,031	1,072	2,628
1985 (estimate)	1,017	445	586	1,446	998	2,440

Cols. A, C, D, E	Included in Bureau of Mines Marketed Production.
Col. B	Excluded from Bureau of Mines Marketed Production.
Cols. A, B, C, E	Projected on basis of Marketed Production Peaking in 1975 at about 26 TCF. Total of these volumes equals FRC Field Use figures.
Cols. A, B, C, D	Assumed to be 1,000 BTU/CF gross heating value.
Col. F	Gross heating value estimated separately for each PAD District.

TABLE LXX

PAD DISTRICT I
TOTAL MISCELLANEOUS NATURAL GAS VOLUMES

Year	Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	Gas Plant Shrinkage BCF	Gas Plant Shrinkage BTUx10^{12}
	CF x 10^9 & BTU x 10^{12}					
1965 (actual)	6	0	2	45	16	32
1969 (actual)	2	0	1	45	10	20
1970 (prelim.)	0	0	1	45	12	25
1971 (estimate)	1	0	1	45	12	26
1972 (estimate)	2	0	1	45	12	26
1973 (estimate)	2	0	1	46	11	24
1974 (estimate)	3	0	1	46	11	24
1975 (estimate)	3	0	1	46	11	24
1980 (estimate)	4	0	1	56	11	24
1985 (estimate)	5	0	1	59	10	21

(A)

PAD DISTRICT I
MIDDLE ATLANTIC REGION

1965 (actual)	3	0	0	4	0	0
1969 (actual)	2	0	0	3	0	0
1970 (prelim.)	0	0	0	3	0	0
1971 (estimate)	0	0	0	3	0	0
1972 (estimate)	0	0	0	3	0	0
1973 (estimate)	0	0	0	3	0	0
1974 (estimate)	0	0	0	3	0	0
1975 (estimate)	0	0	0	3	0	0
1980 (estimate)	0	0	0	3	0	0
1985 (estimate)	0	0	0	3	0	0

(B)

PAD DISTRICT I
SOUTH ATLANTIC REGION

1965 (actual)	3	0	2	38	16	32
1969 (actual)	0	0	1	38	10	20
1970 (prelim.)	0	0	1	38	12	25
1971 (estimate)	1	0	1	38	12	26
1972 (estimate)	2	0	1	38	12	26
1973 (estimate)	2	0	1	38	11	24
1974 (estimate)	3	0	1	38	11	24
1975 (estimate)	3	0	1	38	11	24
1980 (estimate)	4	0	1	48	11	24
1985 (estimate)	5	0	1	51	10	21

TABLE LXXI

PAD DISTRICT II
TOTAL MISCELLANEOUS NATURAL GAS VOLUMES

	CF x 10^9 & BTU x 10^{12}				Gas Plant Shrinkage	
Year	Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	BCF	BTUx10^{12}
1965 (actual)	21	58	63	88	114	287
1969 (actual)	75	158	75	87	123	305
1970 (prelim.)	87	178	79	91	138	341
1971 (estimate)	95	198	83	94	149	367
1972 (estimate)	102	208	86	92	158	388
1973 (estimate)	116	213	87	96	164	401
1974 (estimate)	132	212	88	99	172	420
1975 (estimate)	148	206	89	101	181	440
1980 (estimate)	150	170	84	185	177	417
1985 (estimate)	150	145	74	215	165	388

(A)

PAD DISTRICT II
EAST NORTH CENTRAL REGION

Year	Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	BCF	BTUx10^{12}
1965 (actual)	0	2	2	41	21	45
1969 (actual)	1	1	4	23	16	34
1970 (prelim.)	0	0	4	23	19	41
1971 (estimate)	0	0	4	23	20	42
1972 (estimate)	0	0	4	22	21	45
1973 (estimate)	0	0	4	22	22	47
1974 (estimate)	0	0	4	22	22	47
1975 (estimate)	0	0	4	22	23	49
1980 (estimate)	0	0	4	42	21	45
1985 (estimate)	0	0	4	51	20	42

(B)

PAD DISTRICT II
WEST NORTH CENTRAL REGION

Year	Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	BCF	BTUx10^{12}
1965 (actual)	8	20	15	45	28	71
1969 (actual)	20	26	16	61	42	105
1970 (prelim.)	25	25	15	65	49	121
1971 (estimate)	23	21	16	68	56	138
1972 (estimate)	25	20	17	67	61	150
1973 (estimate)	26	18	18	71	66	162
1974 (estimate)	27	17	19	74	73	179
1975 (estimate)	28	16	20	76	78	190
1980 (estimate)	24	16	20	140	84	198
1985 (estimate)	22	12	20	161	80	189

TABLE LXXII

PAD DISTRICT III TOTAL
MISCELLANEOUS NATURAL GAS VOLUMES

Year	CF x 10^9 & BTU x 10^{12} Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	Gas Plant Shrinkage BCF	Gas Plant Shrinkage BTUx10^{12}
1965 (actual)	521	246	398	241	570	1,516
1969 (actual)	608	284	556	375	681	1,788
1970 (prelim.)	692	322	612	386	749	1,954
1971 (estimate)	754	310	640	418	796	2,071
1972 (estimate)	779	310	643	445	828	2,139
1973 (estimate)	837	310	645	468	835	2,151
1974 (estimate)	872	300	653	495	862	2,206
1975 (estimate)	902	300	661	563	887	2,262
1980 (estimate)	810	270	563	720	830	2,031
1985 (estimate)	760	252	475	1,093	773	1,886

TABLE LXXIII

PAD DISTRICT IV TOTAL
MISCELLANEOUS NATURAL GAS VOLUMES

Year	CF x 10^9 & BTU x 10^{12} Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	Gas Plant Shrinkage BCF	Gas Plant Shrinkage BTUx10^{12}
1965 (actual)	23	9	17	3	18	50
1969 (actual)	14	48	19	5	21	58
1970 (prelim.)	32	32	18	5	24	66
1971 (estimate)	34	34	18	5	25	70
1972 (estimate)	35	35	18	5	26	72
1973 (estimate)	38	34	18	5	27	75
1974 (estimate)	41	33	19	5	28	77
1975 (estimate)	45	31	19	5	29	81
1980 (estimate)	50	30	18	10	27	75
1985 (estimate)	50	30	18	10	25	70

TABLE LXXIV

PAD DISTRICT V TOTAL
MISCELLANEOUS NATURAL GAS VOLUMES

Year	CF x 10^9 & BTU x 10^{12} Used at Leases	Vented at Leases	Gas Plant Fuel & Losses	Used to Mfg. Chemicals	Gas Plant Shrinkage BCF	Gas Plant Shrinkage BTUx10^{12}
1965 (actual)	112	6	32	27	36	107
1969 (actual)	64	36	26	41	31	93
1970 (prelim.)	65	33	26	43	33	99
1971 (prelim.)	54	30	26	43	35	105
1972 (prelim.)	63	28	26	43	35	105
1973 (prelim.)	62	26	25	48	34	101
1974 (prelim.)	61	24	24	50	34	101
1975 (prelim.)	60	22	24	52	34	101
1980 (prelim.)	55	20	20	60	27	81
1985 (prelim.)	50	18	18	69	25	75

As shown in Table LXXV, the closest approximation of these total gas requirements which can be made with Bureau of Mines data is to add the values for "marketed production," "vented and flared" and "net receipts (net imports)" reported by the Bureau of Mines. This only leaves a heating value discrepancy, inasmuch as Future Requirements Committee data are reported in units of billions of cubic feet of 1,000 BTU's gas, whereas the Bureau of Mines uses a nominal heating value of 1,032 BTU/CF. Thus, as shown in Table LXXV, a good approximation is obtained between total gas requirements, including field use, reported by the Future Requirements Committee for the years 1964 through 1968 and the equivalent Bureau of Mines values computed as noted above, by correcting to a common 1,032 BTU/CF heating value basis. There is, however, an unusually large discrepancy of 0.6 TCF in the 1969 data treated in this manner.

Another way of reconciling the differences between the Bureau of Mines and Future Requirements Committee data would be as follows:

Future Requirements Committee = Bureau of Mines gross withdrawals

- Gas for repressuring

+ Imports--exports

± Net storage changes

In addition, discrepancies also are introduced between the Bureau of Mines data and the Future Requirements Committee data because of energy equivalence conversions. The Bureau of Mines data assumes 1,032 BTU/CF. The Future Requirements Committee (in the 1969 report) used 1,000 BTU/CF except for field use. No energy conversion rate was stated for this classification. However, the Gas Demand Task Group also assumed 1,000 BTU/CF was applicable here. In addition, the Future Requirements Committee data also may be greater than the Bureau of Mines due to a greater coverage resulting from the number of organizations reporting to the former.

Two possible methods exist for adjusting the gas requirements reported by the Gas Demand Task Group to correspond to fuel consumptions used by other participants in this study. One simply would be to subtract field use from the data reported by the Gas Demand Task Group and make no adjustments in the other categories. However, this method would reduce the past gas consumption values to below the levels reported by the Bureau of Mines. The other would be to use the historical relationship between computed total requirements and actual consumption shown under the Bureau of Mines heading in Table LXXV.

It can be seen that consumption roughly corresponds to 93 percent of computed total requirements. Since the basic data on "firm residential," "firm industrial" and "interruptible" requirements as used by the Future Requirements Committee are actually consumptions, the application of this factor uniformly over these various categories would introduce errors which would unduly depress these requirements.

Table LXXVI shows the LPG energy requirements, excluding that used for motor gasoline at refineries and chemical requirements. Table LXXVII shows the LPG chemical requirements. This information is not normally included in natural gas requirements, inasmuch as these are reported on a dry (LPG-free) basis.

RELATED MATTERS

There are numerous factors related to the projections shown in this report that cannot be quantified at this time. Some are mentioned here to help put the projected demand in better perspective.

TABLE LXXV

COMPARISON OF RECENT STATISTICS ON NATURAL GAS IN THE U.S.
(TCF at 60 and 14.73 psia)

Year	Future Requirements Committee — 1969 Study† — 1,000 BTU/ CF basis	Future Requirements Committee — 1969 Study† — 1,032 BTU/ CF basis	U.S. Bureau of Mines* — 1967 Study‡	U.S. Bureau of Mines* — Net Imports	U.S. Bureau of Mines* — Net Production§	U.S. Bureau of Mines* — Total Requirements‖	U.S. Bureau of Mines* — Consumption#	American Gas Association — Prelim. Net Production**	American Gas Association — Actual Net Production**	American Gas Association — TOTAL REQUIREMENTS — Prelim. Net Prod. Plus Net Imports	American Gas Association — TOTAL REQUIREMENTS — Actual Net Prod. Plus Net Imports
1960	-	-	-	0.14	13.33	13.5	12.34	13.02	-	13.2	-
1961	-	-	13.8	0.21	13.78	14.0	12.82	13.39	-	13.6	-
1962	-	-	14.6	0.39	14.30	14.7	13.59	13.64	-	14.0	-
1963	-	-	15.2	0.39	15.13	15.5	14.38	14.55	-	14.9	-
1964	16.6	16.1	15.9	0.42	15.80	16.2	15.03	15.35	-	15.8	-
1965	17.3	16.8	16.2	0.43	16.36	16.8	15.60	16.25	16.31	16.7	16.7
1966	18.5	17.9	-	0.46	17.58	18.0	16.76	17.49	17.46	18.0	17.9
1967	19.7	19.1	-	0.48	18.66	19.1	17.80	18.38	18.38	18.9	18.9
1968	21.3††	20.6††	-	0.56	19.84	20.4	18.96	19.37	19.67	19.9	20.2
1969	23.2††	22.5††	-	0.68	21.22	21.9	20.39	20.72	20.97	21.4	21.7
1970	-	-	-	0.87‡‡	N.A.	N.A.	21.85‡‡	21.96	N.A.	22.8‡‡	N.A.

* American Gas Association, *1969 Gas Facts* (New York, 1969); U.S. Bureau of Mines, "Natural Gas Production and Consumption: 1969," *Mineral Industry Surveys* (Washington, D.C., September 3, 1970); U.S. Bureau of Mines, "Crude Petroleum, Petroleum Products, and Natural-Gas Liquids: 1969 (Final Summary)," Petroleum Statements, Annual, *Mineral Industry Surveys* (Washington, D.C., December 15, 1970; U.S. Bureau of Mines, "U.S. Energy Use Sets New Record" (Washington, D.C., March 9, 1971).

† Future Requirements Agency, *Future Natural Gas Requirements of the United States*, Vol. No. 3, prepared by the Future Requirements Committee for the Gas Industry Committee, Future Requirements Agency (Denver Research Institute, University of Denver, Colorado, September 1969).

‡ Future Requirements Agency, *Future Natural Gas Requirements of the United States*, Vol. No. 2, prepared by the Future Requirements Committee for the Gas Industry Committee, Future Requirements Agency (University of Denver, Colorado, June 1967).

§ Marketed production, plus vented and flared.

‖ Net production, plus net imports.

\# 1,032 BTU/CF basis.

** "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1970," Vol. XXV (American Gas Association, American Petroleum Institute and Canadian Petroleum Association, 1971).

†† Future Requirements Agency, "United States Requirements in 1969," *Supplement to Vol. No. 3, Future Natural Gas Requirements of the United States* (Denver Research Institute, University of Denver, Colorado, December 1970).

‡‡ Preliminary estimate.

TABLE LXXVI

LPG ENERGY REQUIREMENTS*
(BTU x 10^{12})

Year	PAD I				PAD II				PAD III	PAD IV	PAD V	Total
	New Eng.	Mid-Atl.	So. Atl.	Total	E. N. Cent.	W. N. Cent.	Other	Total				
1965	19	31	83	133	118	134	46	298	216	27	54	728
1969	23	42	107	172	185	210	66	461	289	42	61	1,025
1970	24	45	110	179	190	210	73	473	298	41	62	1,053
1971	24	45	113	182	197	210	74	481	304	41	62	1,070
1972	24	46	115	185	203	216	76	495	310	44	64	1,098
1973	25	46	118	189	210	222	78	510	321	45	67	1,132
1974	25	47	121	193	216	228	80	524	331	47	70	1,165
1975	26	48	123	197	221	234	83	538	341	49	72	1,197
1980	29	51	134	214	249	259	92	600	385	56	86	1,341
1985	31	54	146	231	281	288	101	670	421	63	98	1,483

* Butane, propane and mixes; includes residential and commercial, internal combustion, utility gas, other and miscellaneous. Excludes LPG to motor gasoline at refineries; excludes chemicals; energy based on average of 98,000 BTU/gallon.

TABLE LXXVII

LPG CHEMICAL REQUIREMENTS*
(BTU x 10^{12})

Year	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
1965	38	34	276	0	15	363
1969	38	36	523	0	17	614
1970	40	40	515	0	14	609
1971	40	55	512	0	13	620
1972	40	72	521	0	13	646
1973	45	75	545	0	13	678
1974	48	84	593	0	13	738
1975	49	86	656	0	12	803
1980	49	96	865	0	13	1,023
1985	49	146	987	0	14	1,196

* Includes ethane, propane and butane from gas plants and refineries; excludes refinery ethylene, propylene and butylenes.

The projected gas requirements included in this task group's report were published by the Future Requirements Committee in the fall of 1969. The figures were developed from data compiled in early spring of that year. Since that time, supply problems have become widespread for many firms. Undoubtedly this will result in some measurable impact on the projected demand expected during the next 15 years. There could be particularly large changes among the various PAD Districts and/or the several use categories outlined in the study. Newer projections to be released in 1971 by the Future Requirements Committee should provide more specific guidance in this area.

Two basic assumptions underlie the projections in the Future Requirements Committee report. These are: (1) "There will be an adequate supply of gas for all estimated requirements for all periods covered by the survey," and (2) "The present-day relationship of the cost of gas to the competing fuels will remain the same in the future. However, individual companies should consider known changes in these relationships in their market area." The appropriateness of these assumptions may be affected by activities now occurring in four general areas:

- *Regulatory:* The recently funded, natural gas survey by the Federal Power Commission undoubtedly will investigate future supply expectations. The New York State Public Utilities Commission has been reviewing the supply situation in that area since mid-1970. The Public Utilities Commission of Pennsylvania also has begun an effort to study the problem in that state. As a result of these and others which may follow, regulatory decisions are expected that could significantly affect the projections of future demand.

- *Category of Usage:* Some distributors already are rationing added supplies to large customers. In addition, certain regulatory bodies have suggested types of service priority. These actions also would serve to readjust future requirements.

- *Environment:* Standards for air quality control issued in early 1971 by the Environmental Protection Agency will add to gas demand. At the same time, general concern for overall environmental quality and the balance achieved in the regulation and administration of standards may affect the availability and timing of new supply. Thus, environmental factors may exercise increasing influence on the balance between demand and supply.

- *Price:* Because of an imbalance of demand and supply, gas prices undoubtedly will be changed from current levels. However, since price changes (both absolutely and relatively) in a free market ultimately affect demand in some way, there is now no way to evaluate the specific influence on individual use categories. Furthermore, the problem of considering inter-fuel price changes upon demand complicates estimates of future requirements.

Chapter Eight

Gas Task Group

Gas Transportation

GAS TRANSPORTATION TASK GROUP

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GAS TRANSPORTATION TASK GROUP REPORT

ABSTRACT

The Gas Transportation Task Group had a single objective: to forecast capital requirements and operating expense for facilities necessary to transport the quantities of gas--natural gas, liquefied petroleum gas (LPG), liquefied natural gas (LNG) and synthetic gas (syngas) projected by the Gas Supply Task Group to be available, proportionately, to the markets projected by the Gas Demand Task Group. The supply volumes projected are substantially less than demand and hence the volumes to be transported are limited to the supply volumes.

The methods developed for projecting capital requirements for different sources and transportation modes in the *U.S. Energy Outlook* study resulted in the following:

SUMMARY OF CAPITAL REQUIREMENTS FOR GAS TRANSPORTATION

Period	Millions of 1970 Dollars
1971-75	3,024.6
1976-80	10,841.2
1981-85	7,097.6
TOTAL	20,963.4

The details of the above capital requirements summary are given in Table LXXVIII. This is followed by a detailed description of the methodology used in determining the estimated capital requirements for each mode of transportation.

TABLE LXXVIII

REQUIRED CAPITAL EXPENDITURES (Millions of 1970 Dollars)

	Gas Pipelines			LNG	LPG		
Period	From Lower 48 Sources	From Alaska and Canada	Revaporized LNG and Syngas	Plants Ships Terminals Storage	Ships Barges and Pipelines	Railroad Cars Trucks	Total
1971-75	879.5	874.0	302.0	675.0	151.3	142.8	3,024.6
1976-80	678.2	3,714.0	1,065.0	5,115.0	149.1	119.9	10,841.2
1981-85	502.2	246.0	1,087.0	4,948.0	176.7	137.7	7,097.6
TOTAL	2,059.9	4,834.0	2,454.0	10,738.0	477.1	400.4	20,963.4
Percent of Total	9.8	23.1	11.7	51.2	2.3	1.9	

SUMMARY OF GAS TRANSPORTATION TASK GROUP REPORT

The Gas Transportation Task Group achieved the objective stated in the "Abstract" on the basis of the following assumptions:

- The location of new natural gas discoveries in the lower 48 states will necessitate the construction of new gathering and feeder-line facilities even though total supplies from this source may remain static or decrease. The facilities for natural gas and LPG transportation are those required to carry the commodity from the producing area to the city-gate or local distributor in the market area and do not include distribution costs.

- Unit costs of the above-mentioned facilities will be greater than historical costs because of (a) more difficult terrain (deeper water for offshore, etc.); (b) new environmental restrictions; and (c) more governmental regulations.

- Total costs of a pipeline from Alaska to the ultimate city-gate delivery points are included.

- Only costs from the U.S.-Canadian border to ultimate city-gate delivery points are included for new imports of Canadian gas and LPG.

- Included in the costs of foreign imports of LNG are (a) liquefaction plants and shipping terminals in producing countries; (b) LNG tanker ships for transportation; (c) receiving terminals, storage and regasification facilities; and (d) new pipeline facilities required for transportation of gas from receiving terminals to ultimate city-gates.

- Costs are included for facilities to receive and transport, to ultimate city-gates, the quantities of syngas projected by the Gas Supply Task Group; however, the plants to convert coal to pipeline gas are not included.

- LPG supplies as projected by the Gas Supply Task Group will continue to be transported to markets projected by the Gas Demand Task Group in the same proportion as presently exists among pipelines, tank cars and tank trucks.

- No new railroad facilities (other than cars) will be required.

- Costs of LPG ships, tankers and barges are included where increased foreign imports are projected.

- No costs are included for natural-gas processing plants.

The projection also includes replacement costs of a capital nature for all types of facilities. Most of the capital required in the 15-year period will be used to replace pipeline capacity from "Lower 48" sources with transport capacity from Alaska, Canada and foreign sources.

PROJECTED GAS TRANSMISSION PIPELINE AND UNDERGROUND STORAGE CAPITAL COSTS

SUMMARY

This section of the report details the total estimated capital investment necessary for incremental expansion of gas pipeline transmission facilities in the lower 48 states and Alaska. All operation and maintenance costs and other cost factors relating to cost of service have been omitted.

The estimated costs for transporting natural gas from points of supply to the five demand PAD Districts are based on a continuing expansion of existing facilities. This assumes that the major load centers will remain in the same relative location within the PAD Districts. The total estimated capital costs (given in Table LXXIX) include domestic, transmission and storage expan-

TABLE LXXIX

SUMMARY OF CAPITAL COSTS
GAS TRANSMISSION PIPELINES AND UNDERGROUND STORAGE
INITIAL APPRAISAL
(Millions of 1970 Dollars)

Total Capital Costs for Additional Facilities	1971-1975	1976-1980	1981-1985
1. Transmission--Domestic	277.036	---	---
2. Transmission--Imports			
a. Alaskan	---	3,714.000	246.000
b. Canadian	874.000	---	---
c. Mexican	---	---	---
Subtotal--Imports	874.000	3,714.000	246.000
3. LNG (Transmission Facilities)	126.000	767.000	630.000
4. Synthetic Gas (Transmission Facilities)	176.000	298.000	457.000
5. Natural Gas Storage	31.398	84.293	56.830
6. New Production Attachments (Not Requiring Additional Transmission Facilities)			
a. Onshore	258.300	268.630	201.474
b. Offshore	312.750	325.260	243.945
Subtotal--New Production	571.050	593.890	445.419
TOTAL	2,055.484	5,457.183	1,835.249

sion, Canadian and Alaskan imports, and connections of liquid natural gas and synthetic gas supplies to existing transmission systems. Capital costs have not been included for natural gas processing plants or synthetic gas plants.

New production attachments refer to additional reserves that will be connected during the 5-year interval. It was assumed that existing gathering systems would not be used for the attachment of new reserves. These attachments will be made regardless of the need for transmission expansion.

METHOD USED

This section details by PAD Districts the estimated capital investment (Table LXXX) necessary to gather, transport and store natural gas. The existing facilities in the United States are too complex to estimate the cost of adding facilities to these systems on a detailed basis. Therefore, a statistical method for estimating additions to existing systems was derived that utilized data furnished by interstate pipeline companies. These data are contained in "Form No. 2" and "Statistics of Interstate Natural Gas Pipeline Companies," published by the Federal Power Commission. New system facilities, including Alaskan and Canadian imports and liquid natural gas and synthetic gas attachments to existing systems, were estimated on a cost-per-mile basis.

The basic approach to the statistical method was to designate transmission corridors through which gas is transported from supply areas to demand areas by PAD Districts. The statistical data was accumulated from all major interstate pipeline companies currently operating within the same corridor.

TABLE LXXX

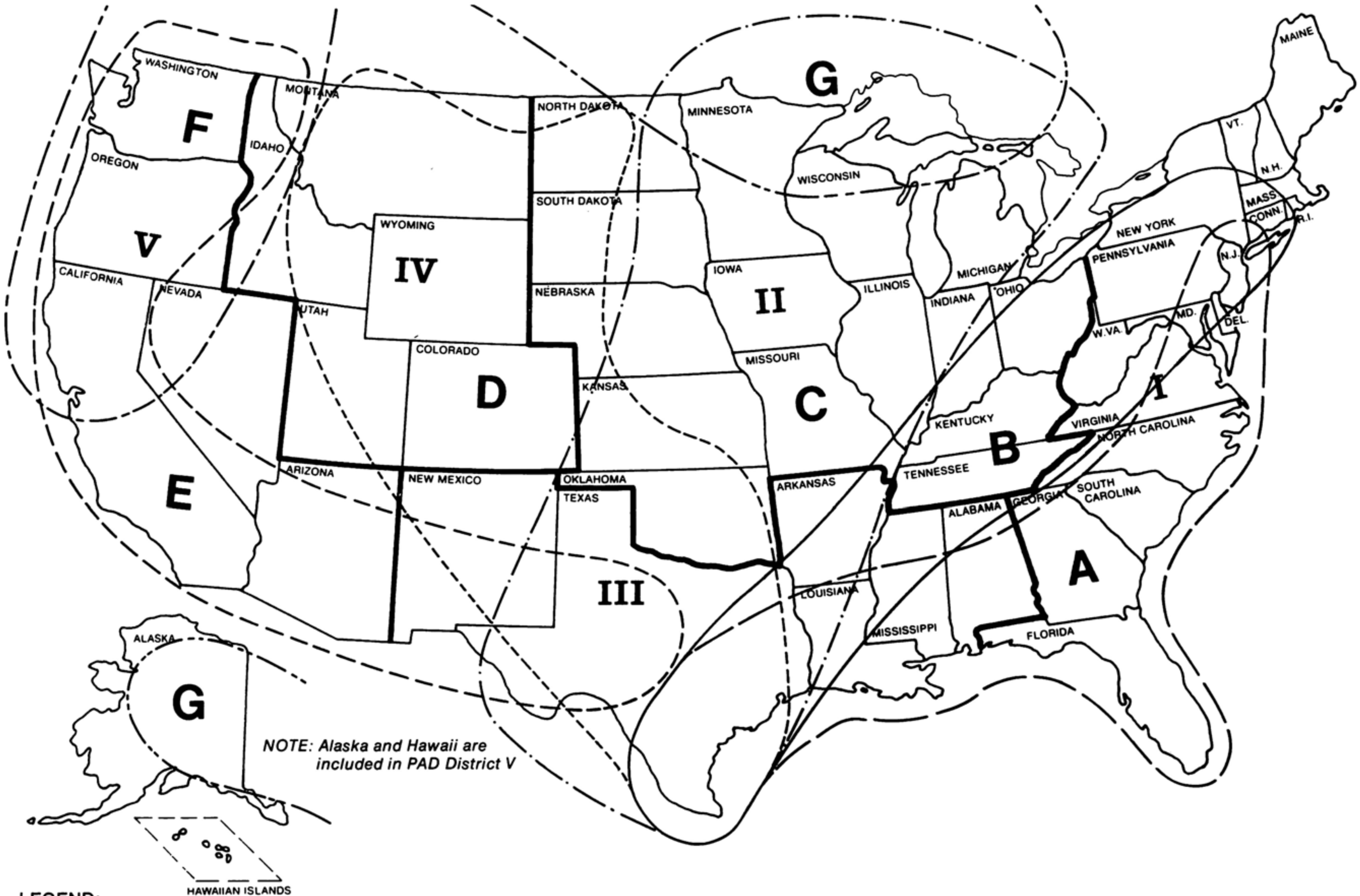
SUMMARY OF CAPITAL COSTS
GAS TRANSMISSION PIPELINES AND UNDERGROUND STORAGE
BY PAD DISTRICTS--INITIAL APPRAISAL*
(Millions of 1970 Dollars)

PAD Districts	1971-1975	1976-1980	1981-1985
I a. New England	38.203	64.261	53.676
b. Mid-Atlantic	416.017	462.854	357.416
c. South Atlantic	282.865	396.288	293.150
Subtotal	737.085	923.403	704.242
II a. East	538.662	2,926.526	767.231
b. West	35.509	33.403	22.419
Subtotal	574.171	2,959.929	789.650
III	278.653	108.659	87.718
IV	7.380	8.199	6.462
V	458.195	1,456.993	247.177
TOTAL	2,055.484	5,457.183	1,835.249
ACCUMULATED TOTAL	2,055.484	7,512.667	9,347.916

* The total capital investment necessary for constructing facilities to transport volumes of gas supply furnished by the Gas Supply Task Group for the initial appraisal are given in the above information. All estimated costs are given in millions of 1970 dollars and have not been escalated to the projected years.

The statistical period used was 1965 through 1969 and then updated to 1970 by applying Nelson Escalation Factors. The accumulation of incremental plant investment and salable gas was then expressed as a cost of facilities per annual unit volume. Then, by refining the basic approach, a capital cost per annual unit volume for transmission, gathering onshore and offshore, and storage facilities was obtained for each PAD District (see Table LXXXI). Escalation factors for the ensuing years are to be supplied by the Capital Requirements Task Group and are not included in this report. All cost estimates are in 1970 U.S. dollars.

Storage withdrawal factors are given in Table LXXXI for each PAD District. The volumetric sum of the total increase in transmission imports, domestic transmission and synthetic gas was multiplied by the storage withdrawal factor yielding the projected volume of gas storage within the PAD District. This volume was then multiplied by the storage cost factor (Table LXXXI) to determine the natural gas storage capital costs for each PAD District.



LEGEND:
Numbers Refer to PAD Districts (Separated by Heavy Lines)
Letters Refer to Gas Transmission Corridors (Outlined by Lighter Solid or Dashed Lines)

Figure 16. Map of PAD Districts Showing Pipeline Corridors.

TABLE LXXXI

CAPITAL COST FACTORS BY PAD DISTRICTS

PAD Districts	Storage	Transmission	Gathering		Storage
	With-drawal Factor	Main $/BCF Annual Gas Sold	Onshore* $/BCF Annual Production	Offshore* $/BCF Annual Production	Market $/BCF Annual Withdrawal
I a. New England	.0127	1,150,000	60,000	450,000	1,120,000
b. Mid-Atlantic	.0127	1,150,000	---	---	---
c. South Atlantic	.0724	1,150,000	---	---	---
II a. East	.0550	1,050,000	60,000	450,000	1,800,000
b. West	.0550	1,050,000	---	---	---
III	.0186	400,000	60,000	450,000	600,000
IV	.0059	1,025,000	60,000	450,000	2,000,000
V	.0096	800,000	60,000	450,000	500,000

* Assumes a reserve to production ratio of 10:1 per the Gas Supply Task Group Report on the initial appraisal.

TABLE LXXXII

CAPITAL COST

Additions BCF/Year	From	To	Year	Size of Added Facilities	Cost Millions of 1970 Dollars
Syngas					
365.0	New York	400 W	1975	2-30"	176
73.0	Casper, Wyo.	Chicago	1980	24"	180
109.5	Garrison, N.D.	Chicago	1980	26"	118
182.5	Casper, Wyo.	Chicago	1985	36"	251
182.5	Garrison, N.D.	Chicago	1985	36"	206
Liquefied Natural Gas					
182.5	Chesapeake Bay	400 W	1975	36"	126
839.5	Chesapeake Bay	400 W	1980	2-36"	252
255.5	Boston	350 W	1980	34"	105
219.0	New York	350 W	1980	36"	110
328.5	Savannah	350 W	1980	36"	110
146.0	San Francisco	400 N-S	1980	30"	95
146.0	Los Angeles	400 N-S	1980	30"	95
839.5	New York	350 W	1985	2-36"	220
693.5	Savannah	350 W	1985	2-36"	220
182.5	San Francisco	400 N-S	1985	30"	95
182.5	Los Angeles	400 N-S	1985	30"	95
Canadian Imports & Alaska Gas					
164.25	U.S. Border	Chicago	1975	48"	459
164.25	U.S. Border	San Francisco	1975	48"	415
584.0	North Slope	Emerson, Manitoba	1980	48"	2,493
584.0	North Slope	Kingsgate, B.C.	1980	48"	1,221
182.5	North Slope	Emerson, Manitoba	1985	(H.P.)	216
182.5	North Slope	Kingsgate, B.C.	1985	(H.P.)	30

All demand volumes were based on the available supply as included in the supply report. The new demand volumes include transmission fuel. The allocation of supply to demand was made on a strict arithmetic percentage calculated by dividing the PAD District volumes contained in the demand report (less field use) by the total demand. Each PAD District was allocated its "fair share" of the total supply based on projected demand. This fair share percentage (Table LXXXIII) was applied to the total supply to determine the allocation of supply for each PAD District. As a practical matter all supply volumes of gas from offshore areas were allocated to PAD District I. All synthetic gas was allocated to the PAD Districts nearest the coal reserves. The liquid natural gas volumes were allocated to PAD Districts No. I and No. V. The Canadian and Alaskan imports were allocated to PAD Districts No. II East and No. V. All of these allocations were made within the framework of the fair share supply policy outlined above.

TABLE LXXXIII

NEW PRODUCTION ATTACHMENTS--FIVE-YEAR CUMULATIVE
(Annual BCF)

		PAD Districts					
		I	II	III	IV	V	Total
	Fair Share Percentage*	18.82%	32.97%	32.14%	2.46%	13.61%	100.00%
1975	Total Production† Additions	941.000	1648.500	1607.000	123.000	680.500	5000.000
	Offshore‡	695.000	--	--	---	---	695.000
	Onshore§	246.000	1648.500	1607.000	123.000	680.500	4305.000
	Fair Share Percentage	19.04%	33.10%	32.07%	2.42%	13.37%	100.00%
1980	Total Production Additions	1075.189	1550.759	1810.993	136.657	626.402	5200.000
	Offshore	722.800	--	--	---	---	722.800
	Onshore	352.389	1550.759	1810.993	136.657	626.402	4477.200
	Fair Share Percentage	19.21%	33.41%	31.90%	2.35%	13.13%	100.00%
1985	Total Production Additions	880.394	1040.786	1461.977	107.701	409.142	3900.000
	Offshore	542.100	--	--	---	---	542.100
	Onshore	338.294	1040.786	1461.977	107.701	409.142	3357.900

* Fair Share Percentage (see p. 116).
† Lower 48 states only.
‡ Area 6A. Based on a 10:1 reserve to production ratio.
§ All other areas 2-2A, 3, 4, 5, 6, 7, 8, 9 & 10. Based on a 10:1 reserves to production ratio.

PROJECTION OF LNG CAPITAL COSTS FOR LIQUEFACTION PLANTS, SHIPS, UNLOADING, LIQUID STORAGE AND REGASIFICATION FACILITIES

Capital costs for facilities for the importation of the quantities and sources of LNG projected by the Gas Supply Task Group are shown in Table LXXXIV. These costs were developed using the following assumptions.

SHIP COSTS

- Using British Petroleum's Sailing Distance Manual, the round-trip nautical mileage for each of the cases concerned was obtained. Ship sailing speed was assumed to average 17.5 knots. Three days for loading and unloading plus one day weather delay were allowed for each voyage.
- Ships were sized to provide for loading sufficient liquid to meet the required delivery plus the necessary boil-off and return-voyage cool-down liquid. It was further assumed that the maximum-sized vessel was limited to 125,000 cubic meters or approximately 792,000 barrels. Maximum loaded capacity was 98 percent of actual volume per U.S. Coast Guard requirements.
- Vessel availability was 345 days per year based upon 20 days' annual docking and survey time.
- Ship costs are based upon published data, two vessels in service and two on tentative order. Costs are from a curve developed and are for complete vessels but do not provide for "interest during construction."
- Some reductions are in order if all deliveries from a single source during one of the projected periods are combined to use a minimum number of the maximum-sized vessels integrating deliveries to the various receiving terminals. This study considers each source and delivery terminal as an individual and separate system. This applies to the liquefaction plants and receiving terminals.

LIQUEFACTION PLANT COSTS

- Liquefaction plant costs are based upon the modular concept, with 150 M^2CF/D used as the most efficient module size. Costs were developed for four different capacity plants and a cost curve was obtained. Plant costs for each case were taken from this curve based on liquefaction required to meet deliveries plus boil-off and cool-down requirements for the LNG tankers.

UNLOADING TERMINALS AND REGASIFICATION PLANTS

- The cost of these plants varies even for the same delivered quantities to various ports due to the difference in storage capacity calculated for each case.
- Storage required was assumed to be equivalent to the number of days of consumption between scheduled ship arrivals plus the capacity of one ship load. Under this system, the storage under all cases varies from 900,000 barrels to 1.47 million barrels, using an assumed cost of $10 per barrel.

GENERAL

- This approach duplicates facilities at both the liquefaction plants and at the discharge terminals as additional volumes are added during subsequent 5-year periods. The costs presented here are based upon the assumption of totally new facilities each time.

TABLE LXXXIV

POTENTIAL LNG SUPPLIES FOR THE UNITED STATES--CAPITAL REQUIREMENTS

	Voyage Route				Capital Requirements (Millions of 1970 Dollars)			
Period	Source - Delivery Point	Quantity BCF/day	Round Trip Nautical Miles	Ships Required	Ships	Liquefaction Plant	Unloading Terminal	Total Capital
1971								
1975	Algeria--Cove Point, Md.	.500	7,484	5	240	170	42	461
	Peak Loading Gas	.300	7,200	3	144	0	70	214
	Subtotal	.800	14,684	8	393	170	112	675
1976	Algeria--Chesapeake Bay	.250	7,484	3	126	100	37	263
	--Savannah, Ga.	.500	7,884	5	260	170	43	473
	--Savannah, Ga.	.250	7,884	3	132	100	37	269
1980	--Chesapeake Bay	.500	7,484	5	240	170	42	461
	--New York, N.Y.	.500	6,926	5	234	170	41	445
	Nigeria--New England	.500	9,530	6	308	172	43	523
	--New York	.500	9,740	6	315	172	43	530
	--Delaware Bay	.500	9,837	6	318	172	43	533
	Venezuela--Cove Point, Md.	.425	3,758	3	125	147	37	309
	--New York	.500	3,804	3	146	165	43	354
	Trinidad--New York	.300	3,864	2	90	108	38	236
	Alaska--Los Angeles	.300	4,480	2	137	108	39	284
	Equador--Los Angeles	.500	6,456	5	224	170	41	435
	Subtotal	5.525	89,131	54	2,664	1,924	527	5,115
1981	Algeria--New York	1.000	6,926	9	466	288	48	802
	--Chesapeake Bay	.500	7,484	5	249	170	42	461
	--Delaware Bay	.500	7,342	5	245	170	42	457
1985	--New England	.500	6,600	5	225	170	41	436
	--Savannah, Ga.	.500	7,884	5	260	170	42	472
	Nigeria--New York	.500	9,740	6	315	172	43	530
	--Delaware Bay	.500	9,837	6	318	172	43	533
	Western Pacific--Los Angeles	1.000	14,000	17	889	320	48	1,257
	Subtotal	5.000	69,813	58	2,967	1,632	349	4,948
	GRAND TOTAL	11.325	173,628	120	6,024	3,726	988	10,738

- For the peak loading gas, i.e., the Distrigas project, no capital for liquefaction plants is included because this is supposedly incremental gas from already existing plants.

PROJECTED TRANSPORTATION COSTS FOR LPG

While Gas Supply Task Group figures indicate that supplies of domestic LPG to be transported over the next 15 years will decrease, the projected supplies from foreign sources more than offset this decrease. Therefore, no new facilities will be required to transport domestic supplies, but some new facilities will be required to deliver projected imports to consuming areas and some facility replacements of a capital nature will be necessary.

Included in this section are projected costs of LPG barges, tankers and marine terminals for these imports. The source of imports is given as North America with deliveries from overseas commencing in the late 1970's. For the purpose of making this transportation cost estimate, we have assumed the sources of these imports as follows:

Year	North America	Overseas
1975	114,000 B/D	6,500 B/D
1980	175,000 B/D	181,200 B/D
1985	225,000 B/D	432,500 B/D

It is estimated that a new pipeline would need to be built to carry a portion of the forecast imports of Canadian LPG. Some Canadian LPG is already being batched in the Interprovincial Pipe Line, and this will continue. The new line would provide for Canadian LPG imports to be marketed in PAD Districts I and II.

Included in this section are capital costs for LPG tank trucks and railroad cars. Costs for LPG tank trucks include only replacement units; costs for LPG railroad cars include some fleet additions.

Also included in this section are costs of tank trucks for the delivery of LNG for peak shaving purposes as distinguished from pipeline facilities for delivery of base-load LNG imports.

These considerations have resulted in the following projected costs of new facilities plus estimated replacement costs of a capital nature.

TABLE LXXXV

NEW FACILITIES AND REPLACEMENT COSTS
(Millions of 1970 Dollars)

	Pipelines & Storage	Tankers Barges & Terminals	LPG Trucks	LPG Rail Cars	LNG Trucks	Total
1971-75	141.8	9.5	73.8	58.2	10.8	294.1
1976-80	77.1	72.0	73.8	31.0	15.1	269.0
1981-85	71.9	104.8	73.8	43.0	20.9	314.4
TOTAL	290.8	186.3	221.4	132.2	46.8	877.5

Chapter Nine

Coal Task Group

Summary of Report

COAL TASK GROUP

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COAL TASK GROUP REPORT

ABSTRACT

U.S. coal demand is expected to grow at a 3.5-percent rate from 519 million tons in 1970 to 734 million in 1980 and potentially to 863 million tons per year in 1985.* U.S. export will grow at a rate of 4.5 percent per year and amount to an additional 71 million tons in 1970 and 138 million tons in 1985.

The *coal reserve position* of the United States is ample and would easily permit a much faster growth rate should coal be called upon to furnish a bigger share of the U.S. demand, whether for conventional uses or for conversion to liquids and gases.

Several major determining factors affect the future of coal, and these must receive proper attention if the forecast is to materialize:

- The program for rapid development of manpower, both mine workers and mining engineers, must be vigorously pursued.
- Developments of improved mining technology must be substantially accelerated to offset the severe impact of the Coal Health and Safety Act of 1969 on production capacity.
- To guarantee the transport of increasing tonnages, the pool of railroad hopper cars as well as the efficiency of car utilization must be increased, and certain locks must be improved in the river system to prevent major bottlenecks. To keep U.S. export coals competitive, better ways must be found to accommodate the new size coal-carrying ships at out ports, notably Hampton Roads, Virginia.
- Technology must be developed to permit use of high-sulfur coal in power generation without polluting the air. Alternate processes should be pursued to fit the widely varying needs of existing plants, new and old, large and small. Desulfurizing by liquefaction and by gasification, as well as by stack gas cleanup, may all be required during the next 15 years. The present substantial research programs in these areas should be further expanded.
- Development of a coal-burning, combined gas/steam power-generating cycle is sufficiently advanced to offer a fairly near-term opportunity for a more economic power plant, capable of being made pollution-free by addition of established sulfur-removal apparatus and including the

*This does not include added demand for coal shown in Extract of Volume One to reconcile task group predictions of fuel demand. Addition of this demand (30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985) would increase the total domestic demand to 933 million tons in 1985, for a growth rate of 4 percent per year from 1970. In the initial appraisal assumptions the projected use of coal as a raw stock for synthetic gas is small and, for projection purposes, may be included in this added coal demand. No coal demand is projected for synthetic liquids in the initial appraisal.

hope of continued increase in efficiency. It could have an important impact on the outlook for coal in power generation during the end of the 1970-1985 period.

- Commercially proved technology to produce synthetic pipeline gas from coal is already available at costs comparable to other supplements to American natural gas (say, $0.85 to $1.15 per million BTU's). Improved technology is now under rapid development which may lower the cost 10 to 15 percent, and such improved systems may be available at the end of the 1970-1985 period. Accelerated commercialization starting immediately could supply 2 to 3 TCF (about 10 percent) of total gas demand by 1985.

- Technology to produce synthetic liquid fuels is less advanced. Proved technology is too outmoded for practical consideration. Coal liquefaction requires added incentives for the development which will cost between $50 and $80 million, including a prototype plant. It would take eight or more years to complete such a program. Initially, the cost of synthetic liquids (distillates) would fall probably between $6 and $7 per bbl based on western strip-mined coal. The rate of commercial application, after the development is completed, could vary widely depending on the need to take the risk. Production of 100 MB/D represents a cautious economic approach, and a maximum of 1 MMB/D appears attainable. After development, costs of $4.50 to $5.50 per bbl appear within reach for conversion of high-sulfur coal to low-sulfur heavy fuel oil (0.3- to 0.5-percent sulfur).

SUMMARY OF COAL TASK GROUP REPORT

DEMAND

The demand for coal in recent years is briefly shown in the following table in relation to the U.S. energy demand as a whole.

	Total U.S. Energy Needs	Domestic Coal Use		Coal as Percent of Total U.S. Energy Needs
	Trillions of BTU's	Millions of tons	Trillions of BTU's	
1965	53,785	454	12,030	22.4
1970	67,827	519	13,062	19.3
Growth Rate	4.7%	-	1.7%	-

To this must be added the more rapid demand for exported coal which reached 71 million tons in 1970. Export coal is needed to support steel operations throughout the Western World and to supply power, mostly in Canada. It is, therefore, included in the demand forecast.

The use of coal in steel making and other industrial applications will continue largely along current lines. There will be continued reduction in the amount of coke needed for each ton of steel, owing to technological advances. The major uncertainty in the use of coal in its present markets is related to the generation of electricity, because of air pollution problems.

Of total coal demand, 83 percent involves only the two markets of coke production and electric power generation--and these two uses are expected to represent 92 percent of all demand by 1985, assuming no conversion of coal to either gas or liquid fuel* during this period. Future demand can, therefore, be fairly well defined by detailed consideration of the steel and power markets which are discussed further below.

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*The potential growth of synthetic fuels industries (synthetic pipeline gas from coal and synthetic hydrocarbon liquids from coal) is covered below in the section titled, "New Technology for Coal Utilization."

The Coal Task Group projects the total domestic demand to grow at a 3.5-percent rate. Projections of total domestic demand by market sectors and by PAD Districts, in trillions of BTU's, are listed in Tables LXXXVI and LXXXVII.

TABLE LXXXVI

U.S. COAL DEMAND BY MARKET SECTOR
(Trillion BTU's)

	1970	1975	1980	1985
Coking coal (14,000 BTU/lb)	2,688	3,136	3,360	3,528
Industrial (13,000 BTU/lb)	2,366	2,262	2,184	2,080
Residential/Commercial (14,000 BTU/lb)	280	196	140	84
Electric Utility (12,000 BTU/lb)	7,728	9,960	12,600	15,696
TOTAL*	13,062	15,554	18,284	21,388
(Average BTU's per Ton--Thousands)	(25,167)	(25,046)	(24,910)	(24,783)

* These quantities are less than the total demand figures shown in Extract from Volume One because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

TABLE LXXXVII

U.S. COAL DEMAND BY PAD DISTRICTS
(Trillion BTU's)

	1970	1975	1980	1985
PAD District I	4,745	5,394	6,071	6,871
PAD District II	6,998	8,416	9,859	11,533
PAD District III	920	1,178	1,503	1,857
PAD District IV	279	416	642	854
PAD District V	120	150	209	273
TOTAL*	13,062	15,554	18,284	21,388

* These quantities are less than the total demand figures shown in Extract from Volume One because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

The figures listed in Table LXXXVI are repeated in Table LXXXVIII in millions of tons per year, together with export demands.

TABLE LXXXVIII

COAL DEMAND BY MARKET SECTOR
(Millions of Tons per Year)

	1970	1975	1980	1985
Blast Furnaces	86	102	110	116
Foundries and Miscellaneous	10	10	10	10
Total Coking Coal	96	112	120	126
Residential/Commercial	10	7	5	3
Industrial	91	87	84	80
Electric Utilities	322	415	525	654
Total Domestic U.S.	519	621	734	863
Coking Coal Export	56	76	94	120
Electric Utility Export	15	16	17	18
Total Export	71	92	111	138
TOTAL*	590	713	845	1,001

* These quantities are less than the total demand figures shown in the basic report because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." See note, previous demand figures.

Although the above categories do not exactly match those used in Volume One to analyze overall energy demand, they are used in this instance in order to bring out the important difference between "coking" and "industrial" markets

1. Forecast for Coking Coal Demand

The production of steel and the impact of future technology on the demand for coking coal were estimated in detail with assistance from the American Iron and Steel Institute. The impact of new technology, such as lower coke rates, direct reduction, etc., are expected to be felt in 1975 at the earliest; thereafter the growth in coking coal demand will lag behind the growth in steel making. Accordingly, U.S. demand for coking coal will grow at a rate of 2 percent per year, but the much faster growth in world steel production is reflected in a vigorous growth rate for U.S. coking coal export of 7 percent per annum. This rate leads to a potential export demand of 155 million tons per year in 1985, but this figure was reduced to 120 million tons (or 5.2-percent Implied Growth Rate) in 1985 to reflect growing foreign competition.

The rapid increase in the cost of the highest quality, low volatile, U.S. metallurgical coal has obviously led to increased efforts by coke oven operators to minimize its use by various changes in technology; the lower figure is forecast to reflect this trend. Even so, metallurgical coal exports are one of the largest items in the U.S. foreign trade balance, approaching $1 billion in 1970, and the forecast implies more than twice this figure in 1985 (in 1970 dollars).

The growth of U.S. "met" coal demand is offset by an expected reduction of "industrial" coal use. This market is forecast to decline at a rate of some 1.0 percent per year. Since residential, commercial and transportation uses of coal are almost negligible in the overall U.S. picture, the balance of the demand then depends on the forecast for use of coal in power generation.

2. *Forecast for Electric Utilities Demand*

The report of the Energy Demand Task Group (Chapter One) commented on the extremely low elasticity of demand to price change for total energy. This lack of elasticity is especially pronounced in power generation owing to the very long lead time between the decision to build a power plant and the date it comes onstream (presently 5 to 7 years). As a result, all the power stations that will operate in 1975 and some 85 percent of those that will operate in 1980, are either existent or already committed as far as design and choice of fuel are concerned. Fuels are not interchangeable between nuclear and fossil-fuel plants, which further limits the flexibility of the demand.

The most important matter bearing on future use of coal in power generation is the impact of the Clean Air Amendments of 1970 (Public Law 91-604). Low-sulfur coals are too scarce to constitute a nationwide answer and the tightening criteria suggest that even fuel with 0.5-percent sulfur will not be usable in wide areas without removal of SO_2 from stack gases. Alternate solutions to the problem are conversion of coal to low-sulfur producer gas (low BTU gas) or to low-sulfur fuel oil ahead of the boiler.

The methodology used by the Coal Task Group to forecast coal demand from electrical utilities was as follows:

- The total demand of electricity (in KWH) was obtained from the National Petroleum Council (NPC) Energy Demand Task Group. (This figure is well backed up by the Federal Power Commission and Edison Electric Institute Studies.)

- The power generating capacity assigned to each fuel, whether currently in existence or announced for startup in the future, is then added for 5-year intervals. For the first half of the 1970-1985 period, this estimate involves little guesswork because most new stations for startup in this period have been announced. The forecast for the second half requires an assumption regarding the use of coal versus gas, oil, hydro or nuclear fuel. As a result, the forecasts by various groups diverge increasingly as they reach further into the future.

- After the generating capacity to be in operation with each fuel is determined for each period, it is necessary to "load" the various segments of the total system. Here, too, judgment is required. The figures used by the Coal Task Group are based on a 70-percent operating factor for all nuclear plants in 1975 and a 74-percent factor in 1980 and 1985. This compares with a 52- to 54-percent average for all fossil-fueled plants and a declining hydropower operating factor (52 to 45 percent).

- The fossil-fuel demand (essentially the remainder after nuclear, hydro and gas turbines have made their contribution) is then estimated for oil, gas and coal, reflecting the capability of existing plants to burn these fuels and giving some consideration to the availability of each for use in power plants. The resulting coal figures are tabulated on p. 127.

3. *Nuclear Impact on Utilities Demand for Coal*

The coal demand forecast is based on nuclear capacity in existence and operating at the stated load factors in 1975, 1980 and 1985 of 50,000, 127,900 and 251,260 megawatts, respectively.

The assumption that the nuclear plant operating factor will be 74 percent, however, must be viewed in the light of an actual average operating factor of only 48 percent achieved so far by the 14 nuclear plants already operating in 1970. Thus, the ability of the nuclear sector to contibute its share at a 74-percent average output is still in doubt, and any shortfall would impact increasingly on the demand for fossil fuels as the nuclear capacity increases. In 1970, when nuclear capacity was only a small part of the U.S. total power plant, its low operating factor was already reflected in a greater demand for fossil fuels.

The following figures give an indication of the sensitivity of estimates of fossil fuel demand to the "nuclear impact." If the average output obtained by the nuclear group in 1975 were to be only 60 percent rather than 70 percent, the estimate of fossil fuel demands would have to be increased 2.7 percent. But in 1985, when nuclear capacity represents a far greater fraction of the total and a 74-percent operating factor is assumed, a drop of the nuclear operating factor to 60 percent would require a 13-percent increase in fossil fuels (including almost 90 million tons of coal). This rise would be required in that one year alone, unless anticipated years earlier.

The coal industry is increasingly moving toward firm, long-term, contract-based operations both in the metallurgical and power markets. This trend reduces the amount of excess mining capacity which can be counted on to permit coal-burning plants to pick up the slack should nuclear plants fall behind schedule in coming onstream or should they prove less reliable in operation than expected. The rate of future commitment to nuclear power, fossil-fueled power and mine development will presumably reflect this consideration.

RESERVES

In 1970 coal supplied only 19.3 percent of the total energy needs of the United States (about 13,062 trillion BTU's out of a total 67,827 trillion), and this percentage contribution is expected to decline further. But against this, one must weigh the fundamental fact that coal represents the largest, most accessible reserve of energy available within the continental United States. This reserve thus commands some attention.

Coal reserves in place (i.e., not necessarily recoverable) are commonly reported as "Measured," "Indicated" and "Inferred." "Measured" reserves are computed from dimensions revealed on the surface or from drill holes. "Indicated" reserves are computed partly from specific measurements and partly from projections of visible data on the basis of geologic evidence. "Inferred" reserves are based on less abundant and reliable data and are NOT INCLUDED in this report.

The Bureau of Mines has reviewed the latest information on "Measured" and "Indicated" reserves and has concluded that the U.S. coal reserves, in beds over 28 inches thick and under less than 1,000 feet overburden, are as follows:

	Millions of Short Tons
Bituminous coal	261,510
Subbituminous coal and lignite	119,861
Anthracite	12,735
TOTAL	394,106

On the basis of 11,000 BTU's per pound (an assumed average value), these reserves should supply 8,670 quadrillion BTU's, one-half of which is recoverable by present mining techniques. This represents a reserve measured in centuries in relation to our projected demand for coal. Until a successful breeder reactor is developed, no other U.S. energy resource is or will be comparable to this reserve. From the point of view of untapped resources, at least, the coal reserves of the United States are sufficient to supply its basic energy needs until the breeder or the fusion reactor, or perhaps solar energy, can remove the ever-growing concern about our ultimate energy sources.

The above figure of 394 billion tons does not include "Measured" and "Indicated" coal seams which are less than 28 inches thick and below 1,000 feet overburden and which are thus beyond current economic mining practices. But these 394 billion tons represent only 25.3 percent of all "Measured" and "Indicated" reserves of more than 14 inches and under less than 3,000 feet cover. the latter will have no significance during the next 15 years, but future needs and new approaches to mining technology can someday place most of these 1,557 billion tons within reach.

1. *Strippable Reserves*

The Bureau of Mines report shows that 85 percent of the 120 billion tons of subbituminous coal and lignite occur in three states--Montana, Wyoming and North Dakota. A considerable part of these are strippable (30 billion tons in PAD District IV) and thus potentially available at the mine site at substantially lower cost per million BTU's than deep-mined coal. This point is of significance if large amounts of additional coal should be needed in the future for conversion to gas or liquid fuels.

By and large, the sulfur content of coals west of the Mississippi is lower than the sulfur content of the reserves in the East and Midwest. Values ranging from 0.5 to 1.0 percent are common. In addition, 5 billion tons of strippable bituminous coal reserves exist in Kentucky, Illinois and Ohio.

2. *Metallurgical Coal Reserves*

Steel making requires a special type of coal, known generally as metallurgical coal. So-called metallurgical coals are needed to produce coke for blast-furnace operation. Metallurgical coals must have a property known as caking (or coking) and must be low in sulfur (under 1.5 percent and preferably well under 1.0 percent). In addition, a high content of fixed carbon is desirable (volatile matter content between 17.5 and 25.0 percent) and ash levels should be low (5.0- to 7.0-percent ash is acceptable).

Coals of this type are in short supply throughout the world. The Bureau of Mines tabulation indicates reserves of 20.3 billion tons of low and medium volatile coals in seams 28 inches or thicker and under less than 1,000 feet cover. This relates to a demand of 96 to 126 million tons per year for the United States. To this must be added the already large and rapidly growing export volume (56 million tons in 1970, potentially 120 million tons in 1985). The U.S. reserve position for metallurgical coals is thus safe for many decades, but is clearly not comparable to that of the coal reserves as a whole.

3. *Adequacy of Reserves*

In summary, the supply of coal reserves in place is adequate to meet the U.S. (and export) demand during the next 15 years and through the rest of the century with a wide margin of safety including, if the need arises, coal for conversion to gaseous and liquid fuels.

COAL MINING

Coal is produced in the United States in both underground and surface mines. Most of the latter involve removal of the overburden (stripping) while auger mining makes up the balance. The contribution of surface mining is large and it is rising:

TRENDS IN USES OF TYPES OF COAL MINING
(Percent of Total Coal Production)

	1960	1965	1969
Deep Mining of Coal	68.6	65.0	61.9
Surface Mining of Coal	31.4	35.0	38.1
TOTAL	100.0%	100.0%	100.0%

Surface mining is attractive because it requires less investment and operating cost (less manpower) and because it is obviously not subject to the health and safety problems associated with deep mining--although it is subject to increasingly stringent environmental requirements. As mining of coal in the Rocky Mountain area increases, the percentage of surface-mined coal is expected to grow even faster.

In spite of the importance of surface mining, however, the future ability of the coal industry to supply its overall share of U.S. energy demand will depend on its ability to produce coal from deep mines. In this connection, the manpower problem will be controlling. Developments of improved mining technology must be substantially accelerated to offset the impact of the Coal Mine Health and Safety Act of 1969 on existing production capacity. These developments will have an even greater impact on the energy supply during the 1985-2000 period, when it may be necessary to reach farther into available coal reserves and to mine thinner seams under deeper cover.

The technical details of mining are described in the full report of the Coal Task Group; only a few brief comments on these and on the industry as a whole are possible in this summary.

1. Underground Mining

Three systems of underground mining are currently in use: so-called conventional mining, continuous mining and long-wall mining. Conventional and continuous mining both involve a room and pillar approach, but they differ in terms of machinery used and in operating sequence. The continuous mining machines permit generally more effective use of manpower. The long-wall system, long prevalent in Europe, has recently entered the United States. It is expected to become increasingly more important because it concentrates production in a smaller area in the mine, offering better productivity and simplified ventilation. Trends in underground mining methods are shown below:

TRENDS IN USES OF TYPES OF UNDERGROUND MINING METHODS
(Percent of Total Coal Production)

Method	1965	1970	1975 (Approx.)
Conventional	45	40	32
Continuous	55	58	63
Long-wall	--	2	5
TOTAL	100%	100%	100%

As a result of continued growth of continuous mining and near elimination of hand loading, the average productivity of manpower has grown fairly steadily at a 2.7-percent rate during the period 1965-1969. Historical data show the following trend in tons per man per day:

RELATIVE PRODUCTIVITY OF UNDERGROUND MINING

(Tons per Man per Day)

	Underground	Total Industry*
1960	10.64	12.83
1965	14.00	17.52
1969	15.61	19.90

* Underground and Surface Mining. See next section, "Surface Mining," for relative productivity of surface mining.

It must be borne in mind, however, that the enactment of the new Coal Mine Health and Safety Act of 1969 has had a profound impact on productivity, and current statistics are not yet able to reflect the final result. Reductions at individual mines from 15 to 30 percent have been reported.

For instance, mine productivity is affected by the dust control provision of the new law which now calls for a maximum of 3 milligrams respirable dust per cubic meter of air. This will drop to 2 milligrams by January 1, 1976. Similar impact results from provisions regarding roof control, ventilation requirements and other limitations of the mining cycle. Interpretation of the new law in the field has not yet reached a steady practice, and the law has been in effect for too short a time to permit analysis of the impact on underground mining. It is hoped that the setback in productivity resulting from the new law can be regained during the next period. In any event, it is now difficult to forecast manpower requirements with confidence.

Underground mines in the United States employed 106,000 men in 1970 to produce 360 million tons. This figure should reach 430 million tons by 1980. Assuming no further loss in productivity for the average of this period, there would be a call for a net addition of 20,000 men. The turnover in the industry is rather high, however, and the total need for recruiting and training will be a multiple of this figure.

Even more crucial is the shortage of professionally trained people. In 1969 the total number of mining engineers in the industry was 3,300. Replacements and modest additions totaling 5 percent of the work force annually would require 165 new engineers each year. Yet the total number of *all* mining engineers expected to graduate in the near future is only about 135 per year.

2. *Surface Mining*

It is necessary to distinguish between area mining and contour mining. Area mining permits operation with a more or less indefinite number of successive pits as typically found in the coal fields of the Midwest and West. Contour mining involves comparatively steep surfaces such as those found in the Appalachian coal fields.

The key figure on which feasibility of surface mining (stripping) depends is the stripping ratio, usually expressed in cubic yards of overburden to be removed to recover one ton of coal. The limiting ratio depends on the value of the coal among other items; hence, actual ratio has reached up to 30:1. Area averages are as follows:

STRIPPING RATIOS--AREA OR STATE

Midwest:	Kentucky	11:1
	Illinois-Indiana	18:1
	Ohio	15:1
Western States:	Overall average	6:1

The Bureau of Mines Coal Reserve Tables, incidentally, show some 25 billion tons of low-rank coals strippable at ratios from 1.5:1.0 to 18:1 in the western states.

The high manpower productivity of surface mining is apparent from a comparison of the figures shown below with those previously listed for underground mining. This high productivity represents one of the main incentives for surface mining.

RELATIVE PRODUCTIVITY OF SURFACE MINING
(Tons per Man per Day)

	Stripping	Auger Mining	Total Industry*
1960	22.93	31.36	12.83
1965	31.98	45.85	17.52
1969	35.71	39.88	19.90

* Underground and Surface Mining.

The high manpower productivity represents one of the main incentives for this type of mining. On the negative side, one must list the increasing opposition to stripping operations, particularly to contour mining. Land reclamation of strip-mined land is currently subject to varying state laws. In general, these laws require grading the mined area and seeding or planting to reestablish vegetation. The cost of reclamation depends on the average amount of coal recovered per acre of stripped land, hence the seam thickness. While the actual amount varies widely, it is not prohibitive *per se* (industry figures range from 5¢ to 25¢ per ton), but proposed stricter reclamation requirements will have a marked impact on stripping cost and will preclude stripping of some reserves.

3. *Structure of Coal Mining Industry*

Some of the problems of the industry relate to the very wide range in the capacity or scope of individual operations. The latest Bureau of Mines statistics are based on 1969 data. In that year, production was distributed as follows:

DISTRIBUTION OF COAL PRODUCTION--1969

Mine Capacity in Tons per Year	Number of Mines	Percent of Total Production
Over 500,000	295	60.3
200 -500,000	263	14.9
50 -200,000	876	15.3
Under 50,000	3,634	9.5
TOTAL	5,118	100.0%

Obviously, the problems of operating a mine producing, say, 25,000 tons per year (about 100 tons per work day) differ tremendously from those of a facility producing 2 million tons per year (about 8,750 tons per work day). The diversity relates to every facet of the industry. The trend is toward increasing mine size. In 1960, the over 500,000-tons-per-year group contributed 49.3 percent of the total; in 1969 its share reached 60.3 percent. This trend will continue.

4. *Days Worked*

The number of days worked per year between 1960 and 1969 were as follows:

TRENDS IN WORKING OF MINES
(Number of Days Worked per Year)

	Type of Mine			
Year	Underground	Stripping	Auger	Total
1960	188	213	119	191
1965	216	238	136	219
1969	215	243	145	226

This trend, too, has probably been disturbed by the Coal Mine Health and Safety Act of 1969 but statistics are not yet available.

Since most coal utilization in steel making and power generation is continuous, seven days per week around the clock, the low number of work days per year may appear surprising. Tradition and current mining methods, however, have prevented a more rational utilization of the rapidly rising investment in mining equipment which is idle, on the average, almost one-third of the time.

5. *Mining Costs*

Coal mining conditions are much too varied to make any comments on "average" costs very meaningful. The mining conditions range from mining 28-inch thick seams under 1,000 feet or more cover and under gaseous conditions to stripping 20-foot thick coal seams with a 1.5:1.0 stripping ratio. A very rough order of magnitude of direct operating costs for a *new deep* mine is given in the following table. Costs are representative of 1970 levels but do not include all the added costs which will result from the new legislation.

	Direct Operating Costs per Ton of Raw Coal
Labor ($40 per day at 15 tons per man day)	$ 2.65*
Supplies	1.75
Power	.18
Payroll Tax and Compensation	.20
United Mine Workers Welfare Fund	.40
Property Tax, Insurance, Misc.	.15
Direct Administration	.10
TOTAL	$ 5.43

* The impact of productivity variations:

At 10 Tons per Man Day	+$ 1.35
At 20 Tons per Man Day	- .65

Equally important, however, is the rapidly rising cost of investment. This results from inflation in the construction business, from more stringent demands for ventilation (more air shafts for a given mine capacity), etc. Depending on depth of cover, thickness of seam, roof condition and required number of working faces, investment may vary between \$8- and \$20-per-ton-annual capacity of uncleaned coal. Mining equipment life is limited, and 8- to 10-percent depreciation rate is commonly applied. To this must be added an adequate incentive as return on investment and associated income tax; 15 percent appears minimal for this type of risk. These percentages imply an added cost of \$1.85 to \$4.60 per ton depending on investment. This, in turn, suggests a total cost between \$6.63 and \$11.38 per ton. Depending on heat content, this might cover a range from \$0.25 to \$0.45 per million BTU's. Royalty for coal was not included and this may range from 0 to 3.0¢ per million BTU's. Furthermore, in the fall of 1971, the industry will be involved in negotiations for a new labor contract which can be expected to increase the labor cost substantially.

The recent price for deep-mined, high-sulfur, steam coal from existing mines in the Appalachian area was near the low end of this range but the new mine investments for added coal production will tend to raise this toward the middle of the range shown above, say, \$9.00 per ton (37¢ per million BTU's), for a 35-percent increase. However, this increase will be somewhat graduated as new mines increasingly replace those now in operation during the 15-year period covered by this study. A cost range of 25¢ to 45¢ per million BTU's for coal at the mine should prevail during the next 15 years.

High-quality metallurgical coals of the low-volatile grades are a special case because these coal deposits are generally much thinner, deeper and more difficult to mine. Hence, prices have been nearer 50¢ to 60¢ per million BTU's. The elasticity of demand as a function of price is even less in coking operations than in power generation.

Compared to these figures, strip mining costs are lower and generally less subject to future escalation. The direct operating costs for *new* strip mines are expected to range from \$1.25 to \$2.75 per ton and investment from \$6 to \$10 per annual ton of mining capacity. Using the same base as for deep mining, the total cost range is from \$2.60 to \$5.00 per ton. The bulk of new strip operations should arise in the western region where coals are generally of low rank (6,500 to 9,500 BTU's per pound). This, too, greatly affects the costs in cents per million BTU's. A range of 15¢ to 25¢ per million BTU's indicates the wide range in possible cost of strip-mined coal.

6. *Capital Requirements*

It is possible to arrive at an order-of-magnitude figure for investment needed to supply the growing demand. The following bases are used: (1) tonnages as shown on coal demand forecast to determine net increase plus a 3-percent replacement of total capacity per year; (2) *a slow growth of surface mining from 38 percent of total production in 1970 to 43 percent in 1985;* and (3) average investment costs for each type of mine, which increase from \$12 to \$15 per annual ton for deep mines and from \$6 to \$9 per annual ton for surface mines, plus the addition of cleaning facilities on one-third of all new mines.

The resulting total to be spent during the next 15 years is \$9.25 billion. Only a minor part of this capital will flow from depreciation; the bulk will require an investment climate for coal mining adequate to attract these funds in competition with other opportunities. This will require an assured long-range outlook for coal in its established markets. Such assurance is an important consideration in view of the long lead time (2 to 4 years) required to open new mining capacity. As a practical matter, there is at present very little spare capacity in the coal industry.

Compared to other forms of primary energy, coal is costly to transport. Thus, utilization at mine mouth offers a real attraction and is likely to grow but, for the 15-year period under study, the impact of this trend can only be limited. The importance of transportation and the high degree of reliance by the coal industry on other industries is demonstrated by the following figures:

Year	Total U.S. Production	Tonnage Originated by Class I Railroads (In Millions of Tons)	Tonnage Waterborne (Long-Haul) Internal, Lake and Coastwise (In Millions of Tons)
1965	520	353	142
1969	561	376	142

These figures are not additive because a substantial amount moves sequentially by rail and barge or lake boat. Thus, almost two-thirds of all U.S. coal depends on rail movement and one-fourth moves on our various waterways. The continued health of these two independent transportation industries is thus of paramount importance to the U.S. energy outlook and is discussed in this section. Coal slurry pipelining is described in the full report of the Coal Task Group.

1. *Railroad Transportation*

An important aspect here is the great interdependence of the coal and railroad industries, which will continue. The following figures demonstrate this.

	1965	1969
Total Coal Freight Revenue ($ Billion)	$1,102	$1,171
Coal as percent of Total Freight, Revenue	11.9%	10.8%
Coal as percent of Total Freight, Tons	25.4%	25.6%

No other commodity approaches coal as a source of freight and revenue. During the last decade, the ratio of rail revenue to mine value has declined from 0.72 to 0.62 due to introduction of the unit train concept, which has helped to increase efficiency of car utilization.

Definitions of the term "unit train" differ. Hence, it is impossible to state precisely what percentage of all coal currently moves by this mode; the figures vary from one-third to one-half. Thus, further increase in efficiency can be expected.

In coal transportation by rail, the term "efficiency" relates largely to utilization of hopper cars. While hopper cars spend 7.7 percent of their total time in line-haul service, this figure is 13.4 percent for all other rail cars, and it is very substantially higher for unit trains which are specifically assigned to given point-to-point movements. The need for further improvement in utilization of hopper cars is emphasized by the ever-present car shortage. This is a serious problem because the majority of mines are not equipped to store coal, and lack of hoppers thus forces shutdown of the mine. The hopper car problem is demonstrated by the following table on car population and total car capacity in the 1965-1969 period.

	1965	1969
Average Size of Car (Tons)	65.6	71.9
Total Number of Cars	425,236	388,609
Aggregate Capacity (Million Tons)	27.89	27.95

During the intervening four years, rail movement grew 7 percent; this growth was achieved by better utilization (longer line-haul service) of cars, not by adding to the fleet. To keep up with the growing demand for coal transport, the fleet must be increased.

It is necessary also to bear in mind that the continued ability of the railroads to serve the expanding coal industry rests upon this national system *in being*. The railroad industry claims that over $36 billion of new expenditures for all plant and equipment is necessary during the next decade. Of this total, between $5 and $6 billion will be required for coal cars and associated motive power. These funds cannot be generated from internal sources alone.

Given such assistance, there is no technical reason why the railroads cannot provide for the future movement of coal, which is expected to grow at a lower rate than coal production due to increased use of coal at mine mouth.

2. *Water Transportation*

This includes movement in barges through rivers and canals, lake shipment and coastwise shipment. The total moved in 1968 was 156 million tons, including 14 million tons of local shipment (shipments within the confines of a port) as well as long-haul tonnage. The total may grow to 205 to 225 million by 1980. Most of this increase will be on the rivers and canals. Some 21 percent of the total waterborne coal in 1968 involved a joint rail-barge movement, and the figure increases to 31 percent if the tidewater and lake ports are included. An efficient system of handling between rail and water is important.

Water transport is attractive, of course, because it is low in cost. Large volume barge movements cost around 2.5 mills per ton mile, and the U.S. average is near 3.0 mills per ton mile. This compares to 5 mills per ton mile for certain unit train hauls and about 9.9 mills per ton mile for the average rail coal haul (in 1965, the last reported figure).

The U.S. system of waterways needs no description here but it is interesting that water transport trends toward long distance. Between 1965 and 1968 water transport grew 9.6 percent; of this growth 38.5 percent involved tonnage which moved over 1,000 miles. Thus, the waterways open markets for coal which otherwise would remain beyond economic reach.

Technological improvement has increased the tonnage of individual tows and brought the power of tow boats into the range of ocean-going ships. Tows of 40,000 tons are becoming common on the lower Mississippi and tows of 36,000 tons have moved on the Ohio. Positive action is required, however, to modernize and enlarge the navigation system to cope with traffic which has reached the economic capacity of certain gateways. Specifically, this bottleneck affects the central interchange of the river system.

The most crucially overloaded locks are numbers 50 through 53 on the lower Ohio River and numbers 26 and 27 south of Alton, Illinois, on the Mississippi. At the Ohio locks numbers 50 and 51, for instance, the aggregate transitting tonnage (millions per year) has grown thus:

	Transitting Tonnage, Locks 50, 51 (Millions of Tons per Year) 1965	1970
Coal Tonnage	7.5	16.0
All Commodities	26.0	43.0

The estimated economic capacity of these locks is 40 million tons per year. Construction of adequate new facilities has now been initiated but will take five years to complete. Thus the growth of coal movement through this reach will be constricted for some years. Construction should proceed expeditiously.

Other segments of the river system are similarly afflicted, and suggested remedies are described in the full report of the Coal Task Group.

A specific problem exists at the Hampton Roads, Virginia, port where most of the U.S. metallurgical coal is loaded for export. Demand for this movement is forecast to grow from 56 million tons in 1970 to 120 million in 1985. Such expansion may require a completely new approach to the port problem or diversion to other ports. Present draft limitations in U.S. harbors are inadequate for vessels over 100,000 DWT, and some way has to be found to accommodate such vessels if U.S. coal is to remain competitive in world markets.

NEW TECHNOLOGY FOR COAL UTILIZATION

1. Control of Sulfur Oxide Emissions

The latest authoritative review of this subject was prepared in 1970 by an ad hoc panel of the National Academy of Science and the National Academy of Engineering (NAS/NAE). The panel stated, *inter alia,* that "commercially proved technology for control of sulfur oxides from combustion processes does not exist" and that "unless the necessary technology becomes available, the country may have to choose between clean air and electricity."

There is, however, a concerted effort under way at this time to solve the problem, sponsored privately by various utilities and supported by the Air Pollution Control Office of the Environmental Protection Agency. Maximum immediate attention is being given to scrubbing of stack gases with various forms of lime, limestone and dolomite. A series of large, but still experimental, scrubbers will be under test by the end of 1971, and an initial solution may be available in the next 1 to 2 years. Presumably, other more economic systems will follow. Several alternatives are already under development, and the driving force for research and development in this area is generally recognized.

The SO_2 removal problem is much more difficult to solve on existing stations which are often cramped for space, where disposal of waste sludge from the scrubbers is very difficult and where operating factors are low. The latter is a particular burden because the high cost of add-on scrubbing equipment cannot be amortized over many tons of coal. At this time, one can expect the cost of 80- to 90-percent SO_2 removal from existing plants to fall into a range of 8¢ to 16¢ per million BTU's for large base-load stations, but costs of 20¢ per million BTU's will easily be exceeded in older peaking plants.

The costs of SO_2 removal are less significant for stations which are initially designed for stack gas cleanup and where efficient removal of particulate matter is combined with SO_2 cleanup.

The key problem for the next 5 to 10 years, in the words of the NAS/NAE panel, is that "...care must be exercised...to insure that realistic criteria and plans are adopted which can be implemented in concert with the development of technology....There is a real danger that the public may be led to expect environmental improvements at a rate that cannot be realized." Even if a commercially proved process were available right now, it would take many years to equip only the most important plants with cleanup devices. The total installed fossil-fuel generating capacity is around 250,000 megawatts (MW); at a low average cost of $25 per KW for cleanup equipment, it would cost $3 billion to fit just half of the U.S. stations with SO_2 removal systems. Obviously this requires time.

2. Combined Power Cycle

All schemes for removal of sulfur oxides imply increased costs except one which is based on a modified power cycle and is thus limited to new plants. In this instance, coal is gasified under pressure; the resulting gas is cleaned and fed to a combined gas turbine/steam turbine system. A 170-MW coal-burning plant of this type, but without sulfur removal, is under construction in Germany and will be watched with a great deal of interest by the U.S. power industry. Essentially all segments of this technology are commercially proved, and the plant is expected to be at least competitive with a plant of ordinary design, yet with addition of established sulfur removal (as in gas-plant practice) it would be pollution-free. The real promise inherent in the combined cycle lies in the potential future increases in gas turbine inlet temperature, which should lead to higher plant efficiency. The system deserves vigorous development; given such support, it could begin to make an appearance toward the end of the 1970-1985 period.

3. *Synthetic Pipeline Gas from Coal*

Interest in this subject has grown recently, and the present state of the art was examined to determine how coal can best serve to fill this energy gap. Coal can, of course, be "converted" to gas most efficiently by direct replacement of natural gas in all those applications where coal can be used, notably in boilers and power stations. However, proved technology is currently available to convert coal to pipeline gas, albeit of somewhat reduced heat content. Coal-based gas will contain from 900 to 925 BTU/CF compared to 1,025 to 1,050 BTU/CF for natural gas.

A satisfactory process of manufacturing synthetic gas from coal is presently available for commercial use. Developed over 30 years ago by Lurgi G.m.b.H. of Germany, this process has been in commercial use ever since. The Lurgi process is particularly suited for non- or mildly caking coals and requires a feed size generally above 1/4 inch. Most western and mid-western coals can be used, and strip mining generally minimizes the production of minus 1/4 inch to the point where the amount of fines is just adequate for the auxiliary boiler needed to make process steam.

The economics of this process has been appraised and an order-of-magnitude cost of gas developed. Results are shown in the table below for a plant with a capacity of 270 million CF/D which produces 900 BTU/CF gas. This plant would have a capital cost of $209 million or $875 per million BTU's daily capacity.

Operating and Capital Costs of Synthetic Gas Plant

	Per Year	Per Million BTU's of Gas
Cost of Coal*	$17,900,000	22.2¢
Operating Cost	16,100,000	20.0
Capital Charge†	37,700,000	46.7
TOTAL	$71,700,000	88.9¢

* Assumes western strip-mined coal at 15¢ per million BTU's converted to gas at 68-percent thermal efficiency.

† At 18 percent.

Specific coal prices and quality and location will result in costs varying from $.90 to $1.10 per million BTU's for gas from western strip coal to $1.05 to $1.25 for gas from eastern shaft-mined coal.

Several new gasification processes have reached the pilot plant stage of development. These new processes offer potential savings in plant investment from 15 to 20 percent. While the savings appear greater when one considers solely the process plant proper, there are major segments of overall plant cost which remain unaffected by selection of process.

As a result, the new processes offer savings between 8¢ and 12¢ per million BTU's in the price of synthetic gas; they may become available at the middle of the 1970-1985 period. Some $80 million will be spent on these pilot plants, and it will then be necessary to demonstrate the new technology in a plant representing a single full-size reactor train. Such a unit will cost $100 million. The incentive for such a development is ample; if synthetic gas were to supply 3 TCF per year at the end of the period (10 percent of expected demand) and the new development were to save 10¢ per million BTU's, the annual saving is $300 million.

The maximum potential growth and associated capital demands for pipeline gas from coal is shown in Table LXXXIX(A). This is the maximum amount of capacity that could be added without regard to economic considerations and assuming that a full program is begun immediately, utilizing existing technology.

TABLE LXXXIX

POTENTIAL GROWTH OF SYNTHETIC FUEL INDUSTRY

(A)

PIPELINE GAS FROM COAL

(Assumes Existing Technology and Immediate Accelerated Rate of Buildup)

YEAR (End)	CAPACITY ADDED TCF/Yr	CAPACITY CUMULATIVE TCF/Yr	MILLIONS OF $ INVESTED Plant	Strip Mines*	Total In Year	Total Cumulative
1975	0.08	0.08	210	40	250	250
1976	0.16	0.24	420	80	500	750
1977	0.16	0.40	420	80	500	1,250
1978	0.25	0.65	600	120	720	1,970
1979 thru 1985	0.33(ea.yr.)	3.0†	800(ea.yr.)	160(ea.yr.)	960(ea.yr.)	8,690

* Total mining capacity (strip) in 1985: 225 million to 250 million tons per year (8 to 9 billion tons reserves).

† Three TCF per year (approximately 36 units, 250 MMCF/D each).

(B)

SYNTHETIC LIQUIDS FROM COAL

YEAR (End)	CAPACITY ADDED MB/D	CAPACITY CUMULATIVE MB/D	MILLIONS OF $ INVESTED Plant	Strip Mines*	Total In Year	Total Cumulative
1.	(Assumes New Technology Available in 1978 and Conservative Rate of Buildup)					
1981	30	30	200	20	220	220
1985	50	80	320	35	355	575
2.	(Assumes New Technology Available in 1977 and Accelerated Rate of Buildup)					
1980	50	50	320	50	370	370
1981	100	150	600	100	700	1,070
1982	100	250	600	100	700	1,770
1983	200	450	1,100	200	1,300	2,070
1984	200	650	1,100	200	1,300	3,370
1985	200	850	1,100	200	1,300	4,670

* Total mining capacity (strip--accelerated buildup) in 1985: 140 million to 150 million tons per year (5 to 6 billion tons reserves).

Note: Compare these capital requirements with those needed for expansion of power generation capacity: The total capacity is expected to grow from 340,000 MW in 1970 to 977,000 MW in 1985. At $200/KW installed cost, the capital requirements will grow from about $6 billion in the beginning of the period to $12 billion in 1985.

4. Synthetic Hydrocarbon Liquids from Coal

Production of synthetic liquid fuels from coal requires development of new technology in hydrogenation of coal or coal-derived intermediates and in production of hydrogen, also from coal or coal-derived material. The hydrogen is produced substantially by the same process as for production of pipeline gas, and the demonstrated technology presently available is sufficiently close to new alternates to serve for an appraisal of the subject.

The hydrogenation step proper has been under development intermittently ever since World War II when some 100 MB/D of liquid fuels were produced from coal in Germany. Several significant improvements have since been tested which would be required to bring coal liquefaction within reach of practical economics under U.S. conditions. The key step involves the use of efficient catalysts under the high pressures needed for the process. The so-called ebulating bed reactor offers the best hope, and this has been evaluated by Hydrocarbon Research, Inc. Information published by H.R.I. was selected to appraise the liquefaction problem.

To forecast liquefaction economics on a realistic bases calls for judgment regarding the uncertainties in detailed engineering and engineering changes resulting from the yet incomplete development. These are estimated to add 24 percent to the initial plant estimate which reflects a fully proved commercial process. The total investment, including manufacture of hydrogen from coal, is expected to fall between $6,000 and $8,000 per daily barrel of synthetic crude.

Bituminous coal at $6.50 per ton (27¢ per million BTU's) and a return of 10 percent discounted cash flow on capital, would yield a price from the first plant for the resultant liquid (syncrude of approximately 32° API gravity) of $7.50 per barrel and the sale of some high BTU gas at $1.00 per million BTU's. The figure would be 50¢ to 75¢ per barrel less for western (U.S.) coal. The lower coal price there is offset by lower coal quality and increased demand for expensive hydrogen. Plant size, too, has some effect although multiple reactors are needed in most plant sections; the above figures, developed for 30 MB/D capacity, might drop 50¢ per barrel for a 100 MB/D plant.

Once the process is developed and applied in large plants on western strip coal, costs in the range of $6.00 to $6.25 per parrel can probably be reached.

A more limited objective is the conversion of high-sulfur coal to low-sulfur heavy fuel oil for power plant use. Hydrogenation of coal removes a substantial part of sulfur while the coal substance is liquefied. A process can probably be developed, and preliminary estimates suggest a cost of $4.50 to $5.50 per barrel for a fuel oil of approximately 0° API gravity containing 0.3- to 0.5-percent sulfur. This could be of considerable interest within the next 15-year period.

The intermittent nature of American interest in coal liquefaction has been alluded to, yet this is a very major and complex technical development which requires sustained effort. Over a 5- to 8-year period, including pilot plant and prototype plant demonstration, a total of $50 to $80 million will be needed before the first commercial-size plant can be built with assurance. The incentive to engage in such an effort has not been sufficient in the past to sustain it for a sufficient length of time. The long lead time implicit in these estimates suggests that this work should at least be started well ahead of the time when the economic incentive is obvious. This requires a policy decision at the appropriate levels of private industry and government.

The potential impact and associated capital demands for synthetic liquids from coal appears in Table LXXXIX(B).

Chapter Ten

Nuclear Task Group

Summary of Report

NUCLEAR TASK GROUP

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NUCLEAR TASK GROUP REPORT

ABSTRACT

Under the conditions of economic climate and of government policy and regulation assumed to exist for this initial appraisal of the 15-year period 1971-1985:

- *U.S. nuclear fuels demand* is expected to grow from 6,900 tons per year of U_3O_8 in 1971 to 59,300 tons per year of U_3O_8 in 1985. This represents a cumulative U.S. requirement for uranium of about 450,000 tons over the 15-year forecast period, not including the reserves necessary in 1985 to sustain operation. All of this requirement comes from electrical utilities.

- The *uranium resource position* of the United States appears adequate with respect to low-cost uranium to meet the total projected demand for nuclear energy. Thus availability of uranium imposes no constraint on projected output in the 15 years through 1985, and domestic uranium could perhaps be called upon to support even a larger growth rate, given appropriate economic incentives.

There are several major factors which affect the future of nuclear fuels and which must receive proper attention if this forecast is to materialize:

- Long-range purchase arrangements providing adequate incentive and sufficient lead time are necessary to develop the full potential for discovery in this emerging industry. It is estimated that 390,000 tons of reasonably assured reserves of U_3O_8 exist in the U.S. and that an additional 680,000 tons is available at product costs (development, mining and milling) up to $10 per pound.

- It is assumed that government policy will continue to be directed to the maintenance of a viable domestic industry and that policies with respect to disposition of government uranium stocks and the enrichment of foreign uranium in government-owned plants for domestic use will be consistent with this objective. For the purposes of this study it was assumed that the 450,000 tons of U_3O_8 required through 1985 would be furnished by the domestic industry.

- Although lower radon limits have been announced, it is assumed that this regulation will not be administered so as to materially restrict uranium production. This is an important assumption, since it is estimated that about one-half of the presently proved domestic uranium ore reserves will be produced from underground mines.

- An estimated $5 billion in capital investment must be made for uranium exploration and to provide the facilities necessary for domestic mining and milling, refining and converting, enriching, fabricating and reprocessing of uranium for use as a fuel in nuclear power plants. In assessing the significance of these capital requirements two factors should be considered: (1) the uniqueness of the nuclear fuel cycle and the newness of the technology involved in comparison with fuel forms for fossil-fueled plants, and consequently the relatively greater opportunities for improving the nuclear fuel cycle; and (2) the somewhat larger investment in nuclear generating plant facilities than in comparable fossil-fueled plants.

- Although reactor technology to improve the utilization of nuclear fuels will continue to progress, new types of reactors will not materially affect uranium demand before 1985.

- The forecast of uranium demand is based on the AEC projection, which the task group adopted, that installed nuclear power capacity will be 300,000 MWe in 1985 and that this capacity will generate 2,067 billion KWH. Serious delays in the installation of nuclear power plants resulting from siting, environmental and construction problems must be avoided if nuclear power supply is to attain this level.

SUMMARY OF NUCLEAR TASK GROUP REPORT

This report provides an analysis of the nuclear energy outlook (i.e., nuclear electric power generation and nuclear fuels requirements) for the United States during the 15-year period 1971-1985, assuming the continuation of government policies which were in effect at the beginning of this period and adopting the estimate of electrical energy demand described in the basic interim report.

Present government policies and programs and other factors are identified that bear significantly on nuclear electric energy demand and supply. Within the context of the identified factors and the adopted electrical energy demand, nuclear energy for power generation is forecast, and the availability of nuclear fuel resources in the United States and non-Communist areas elsewhere to meet these requirements is estimated.

ASSUMPTIONS USED FOR THIS STUDY

The broad assumption for this initial appraisal is that present government policies, programs and practices will be continued through 1985 without significant change. Within the context of this broad assumption, the following government policies and programs and other factors bear significantly on nuclear electric energy demand and supply and are assumed to prevail during that period as indicated. *In this regard, it should be noted that this report on the initial appraisal does* not, *because of the assumptions made, constitute a probable forecast of the future and should not be so interpreted.*

1. *Health and Safety and Environmental Factors*

a. Mines

Radon concentration in the mines and nonradiological mine hazards are regulated by governments. Although lower radon limits have been announced, it is assumed that such regulation will not be administered in such a manner as to materially affect the ability of underground uranium mines to maintain and expand production. It is estimated that approximately one-half of the presently proved domestic uranium ore reserves will be produced from underground mines.*

b. Use of Nuclear Fuels

The possession and use of nuclear fuel materials throughout the nuclear fuel cycle, and the construction and operation of nuclear power facilities and commercial chemical reprocessing plants, are subject to federal and state licensing and regulation to protect the health and safety of the public from radiation hazards.

*Based on information published in the U.S. Atomic Energy Commission's *Statistical Data of the Uranium Industry* (Grand Junction, Colorado, January 1, 1971).

In addition, nonradiological environmental aspects will be considered in the issuance of nuclear reactor licenses in accordance with applicable federal and state environmental standards.

In the long term, environmental considerations are not expected to materially retard the growth of nuclear power or alter its competitive position. In the near term they will tend to delay construction and to increase the cost of nuclear power through limitations on siting and thermal discharges, but air pollution associated with the use of fossil fuels will accelerate the trend toward nuclear power generating facilities.

2. *Technology for Nuclear Fuels*

a. Government R&D (Including Financing Support)

The government will continue extensive research and development on:

- Fission breeder reactors--which make available virtually unlimited energy from known uranium resources
- The safety aspects of currently available types of reactors
- Fusion reactors--which could also, if successful, supply unlimited energy.

b. Domestic Nuclear Plant (1971-1985)

Plutonium (Pu) recycle is expected to commence in 1974. Recycling of plutonium will be continued in the United States through 1985.

The high-temperature gas reactor will not materially affect uranium demand through 1985, but will have an impact thereafter.

Fast-breeder reactors will not significantly influence the quantity of uranium required before 1985.

3. *Government Indemnification*

The Government will continue to provide liability indemnification and protection to the public in the event of an incident in which there is a damaging release of nuclear radiation (currently provided under the 1957 Price-Anderson amendments to the Atomic Energy Act).

4. *Imports*

Uranium enriched in U.S. government-owned facilities for use in domestic reactors will continue to be of U.S. origin as required to ensure that a viable domestic uranium mining undustry exists. Uranium may be imported for enrichment in U.S. government-owned facilities if it is to be re-exported for use in reactors abroad. (See last paragraph of section B, Nuclear Growth Forecast--Uranium Requirements, p. 149, concerning the quantities of uranium assumed for this study to be furnished by the domestic industry.)

5. *Uranium Stocks*

The U.S. Government will pursue its stated policy of disposing of excess uranium stocks, estimated at about 50,000 tons of U_3O_8, in a manner which will not adversely affect the general viability of the domestic uranium industry.

It is assumed that virtually all domestic uranium production will be used for nuclear power plants through 1985, i.e., U.S. Government requirements for nuclear materials will be satisfied from government stocks (see p. 149).

6. *Depletion*

The depletion allowance for uranium has been reduced from 23 percent to 22 percent. It is assumed that the depletion allowance or other incentives for exploration and mining, consistent with those provided for other minerals, will be continued in order to attract the necessary risk capital and to promote the continued development of uranium supply.

7. *Ownership and Operation of Uranium Enrichment Plants*

The Government presently owns the gaseous diffusion plants used in enriching uranium in the United States. The possibility of private ownership and operation of enriching facilities in the future has been receiving attention. New enrichment capacity, when added, will use gaseous diffusion technology.

It is assumed that a factor of $32 per kilogram unit of separative work will be used for gaseous diffusion enrichment services and that a 0.20 percent U_{235} assay will be utilized for tailings from gaseous diffusion plants (see fourth footnote, Table XC).

8. *Mining Laws and Public Lands*

Public lands, an important source of uranium, will continue to be available for mineral development in the United States. Modifications to the mining laws as proposed by the Public Land Law Review Commission are not expected to materially change the position of uranium producers.

9. *Antitrust*

Government policy will continue to permit free competition between nuclear and other energy sources.

The regulatory activities of the Atomic Energy Commission will include consideration of the antitrust aspects of license applications for proposed nuclear power plants. Antitrust considerations could be significant in particular instances, but are not expected to affect the growth of nuclear power as a whole.

10. *Waste Management*

The nuclear power industry generates radioactive wastes which must be isolated from the biosphere for long periods of time. The cost of such disposal is assumed to be small* compared to the overall cost of the power generated. However, a waste disposal system that embodies adequate health and safety considerations will have to be developed.† The present essential features of AEC regulatory policy will be continued on radioactive waste pertaining to time of commercial storage, commercial performance criteria, use of federal repositories, and bearing of repository costs.

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*Because there is a 10-year lag between taking delivery of irradiated fuel and the disposal of waste fission products, additional capital investment for such storage is not believed to be significant prior to 1985.

†The Atomic Energy Commission has announced the tentative selection of a site near Lyons, Kansas, for the location of a demonstration Federal Repository. Conceptual designs for a demonstration facility are being developed.

TABLE XC

UNITED STATES AND NON-COMMUNIST FOREIGN REQUIREMENTS FOR NUCLEAR POWER REACTORS

Calendar Year	Installed MWe†	Tons U_3O_8‡ Annual	Tons U_3O_8‡ Cumulative	Annual Separative Work MT SWU‡
United States*				
1971	11,000	6,900	6,900	3,200
1975	59,000	18,400	66,200	10,500
1980	150,000	34,200	206,000	20,500
1985	300,000	59,300	450,000	37,400
Non-Communist Foreign§				
1971	12,400	7,400	7,400	1,900
1975	37,000	16,300	56,600	6,000
1980	127,000	34,500	191,000	14,800
1985	270,000	60,400	440,000	33,300
Total Non-Communist World§				
1971	23,400	14,300	14,300	5,100
1975	96,000	34,700	122,800	16,500
1980	277,000	68,700	397,000	35,300
1985	570,000	119,700	890,000	70,700

* Uranium and separative work requirements based on plutonium recycle commencing in 1974.

† Installed generating capacity of nuclear power plants measured in megawatts of electricity (MWe). The energy supply (measured in trillion BTU's, rounded) to fuel U.S. nuclear power plants would be: 240 in 1970; 3,340 in 1975; 9,490 in 1980; 21,500 in 1985.

‡ Uranium and separative work requirements assume "tails" of 0.2 percent at gaseous diffusion plants (GDP). The AEC has recently suggested that industry use a projected level of 0.25 percent as a tentative figure for planning purposes, starting in 1973. A level of 0.25 percent would increase U.S. uranium requirements on the order of 10 percent.

§ Uranium and separative work requirements include requirements for natural uranium reactors without plutonium recycle, foreign light water reactors commencing plutonium recycle during 1974, and the British advanced gas-cooled reactors (AGR's) without plutonium recycle.
AEC has assumed separative work requirements in the U.S. during 1985 for foreign LWR's to be 18,400 MT SWU (Metric tons, separative work units).

Source: U.S. Atomic Energy Commission, *Forecast of Growth of Nuclear Power,* WASH-1139 (January 1971).

11. *Safeguards*

It will continue to be the policy of the Government to assure against the diversion of special nuclear materials to unauthorized uses through the establishment of a system of domestic safeguards and the development and establishment of effective international safeguards. It is assumed that the U.S. Government policy on nuclear safeguards will not have any significant effect on the growth of nuclear generation.

12. *International Relations Other Than Import Policy*

It will continue to be the policy of the United States to cooperate with friendly countries in the peaceful uses of atomic energy by the supply of nuclear equipment, fuel and related material.

13. *Costs*

Cost estimates developed for this study are based on use of 1970 dollars.

NUCLEAR GROWTH FORECAST--URANIUM REQUIREMENTS

The foregoing assumptions are compatible with those used in an AEC forecast of nuclear power growth.* Therefore, in predicting what domestic growth is likely to be, the Nuclear Task Group saw no reason to depart from the prediction of the AEC. The AEC forecast is basically an extrapolation of 1960-1975 data on nuclear and conventional plants installed, under construction and definitely planned by utilities. (Plants having a capacity under 100 MWe and those used specifically for peaking purposes were excluded.) If needed, domestically produced nuclear fuel can furnish a larger part of the energy for power generation if the industry is given adequate incentives and sufficient lead time.

The forecast for the growth of nuclear power in other countries in the non-Communist world generally follows the same approach as used in the domestic forecast.

In translating the forecast growth in U.S. nuclear power generation into nuclear fuel requirements, several assumptions were necessary concerning the expected design and operating characteristics of domestic nuclear plants. For example, where reactor types were not known, the AEC assumed that additions to capacity in MWe will be divided among boiling-water and pressurized-water units in the respective proportions of one-third and two-thirds. The AEC also assumed that the thermal efficiency of boiling-water plants would be 34 percent while that of pressurized-water plants would be 33 percent.

Capacity factors for new atomic plants were estimated by the AEC as follows:

Operating Level as Percent of Capcity (Capacity Factor)*

Year of Starting Commercial Operation	1st Year of Operation	2nd Year of Operation	3rd Year of Operation
1975 and earlier	50	70	80
1976-1980	60	80	80
1981-1985	80	80	80

* Once the level of 80 percent is reached, it is used through the remaining years of the forecast.

*U.S. Atomic Energy Commission, *Forecast of Growth of Nuclear Power*, WASH-1139 (January 1971).

Summary forecasts of nuclear power growth and of uranium and separative work requirements for the United States and non-Communist foreign countries are given in Table XC. A forecast of distribution of nuclear energy by PAD Districts is given in Table XCI. Such a breakdown of the United States into smaller geographic divisions is not necessary for an analysis of supply and demand for nuclear fuels, because transportation costs are minor. However, a geographical distribution is provided for use in analyzing the supply of other fuels.

TABLE XCI

DISTRIBUTION OF NUCLEAR ENERGY BY PAD DISTRICTS
(Trillion BTU's)

PAD District	1970	1975	1980	1985
I	147	1,691	4,490	9,953
II	32	1,076	2,880	5,822
III	---	287	861	2,255
IV	---	21	31	82
V	63	267	1,230	3,075
TOTAL	242	3,342	9,492	21,187*

* 21,469 if Puerto Rico in included.

Source: U.S. Atomic Energy Commission.

As indicated in Table XC, cumulative U.S. uranium requirements over the 15-year forecast period--all of which come from demand by electric utilities and were assumed to be furnished by the domestic industry--are about 450,000 tons. These requirements, however, are only to meet fuel needs during the period. The maintenance of a forward ore reserve will be required. This is discussed in the following two sections on uranium resources and capital requirements.

URANIUM RESOURCES

Adequate uranium reserves can be developed within the United States from the presently estimated low-cost* resource of 1,070,000 tons of U_3O_8 (see Table XCIII, p. 152) to meet the total projected cumulative nuclear requirement of 450,000 tons of U_3O_8 (Table XC) for the domestic power generation industry for the 15-year forecast period 1971-1985, provided the economic and regulatory climate is such as to encourage the required exploration and the large investment of sufficient capital for mines and mills.

This assessment takes into account the probability that investment in exploration sufficient to find and maintain more than 10 to 12 years' forward

*"Low-cost" refers to uranium reserves that can be developed, mined and milled at costs up to $10 per pound.

reserves to any point in time is unlikely and the fact that increased exploration has historically yielded an improved reserve position. Should low-cost uranium ($10 or less per pound of U_3O_8) not be developed as anticipated, demand could be filled in any case by the use of higher-cost material. Past experience in this country has shown that exploration and development of uranium deposits have increased sharply during the periods when incentives were attractive and more than adequately met market requirements. Consequently, the supply of uranium within the period being studied will be determined by economic rather than geologic considerations.

During the years a close relationship has been observed between exploration activity and uranium discovery (Table XCII and Figure 17). As production exceeded discoveries because of a virtual cessation of exploration, reserves gradually declined during the early 1960's until a low point was reached in 1966. Since that time reserves have been on the upswing and the increases for 1969 and 1970 have been substantial. At the end of 1970, the reasonably assured reserves had increased to 390,000 tons of U_3O_8.

There is a lag time between the resurgence of drilling effort and increases in reserves. This lag is a reflection of the time required to discover deposits, carry out exploration drilling, and gather and evaluate data.

Besides U_3O_8, thorium is another nuclear fuel resource, but prospective requirements for thorium through 1985 seem unlikely to exceed a few thousand tons. Because thorium reserves are very large in relation to the small requirements, they do not require analysis in the Interim Report.

TABLE XCII

URANIUM SURFACE DRILLING STATISTICS--1948 THROUGH 1970

Year	Feet Drilled (Thousands)	Number of Holes (Thousands)	Average Depth (Feet)	Addition to Reserves: Tons U_3O_8 (Thousands)	Addition to Reserves: Tons Per Hole	Addition to Reserves: Pounds Per Foot
1948	210	--	---	.1	---	.8
1949	413	--	---	1.3	---	6.3
1950	778	--	---	2.3	---	5.9
1951	1,428	--	---	2.4	---	3.4
1952	1,662	--	---	2.8	---	3.4
1953	4,015	--	---	10.2	---	5.1
1954	4,610	--	---	15.9	---	6.9
1955	6,029	--	---	44.4	---	14.7
1956	8,790	--	---	61.1	---	13.9
1957	9,200	--	---	55.9	---	12.2
1958	7,253	48.3	151	29.5	.61	8.1
1959	5,679	35.8	158	32.7	.91	11.6
1960	5,610	31.7	177	9.6	.30	3.4
1961	4,509	27.6	163	4.8	.17	2.1
1962	3,914	19.3	203	9.1	.47	4.6
1963	2,857	22.0	130	7.7	.35	5.4
1964	2,213	15.9	139	5.9	.37	5.3
1965	2,113	13.6	155	3.6	.26	3.4
1966	4,200	18.9	222	5.8	.31	2.8
1967	10,764	29.7	362	17.7	.60	3.3
1968	23,800	58.0	410	26.0	.45	2.2
1969	29,900	75.9	390	56.0	.74	3.7
1970	23,500	59.0	398	55.0	.93	4.4
TOTAL	163,417	--	---	460.0	---	5.6

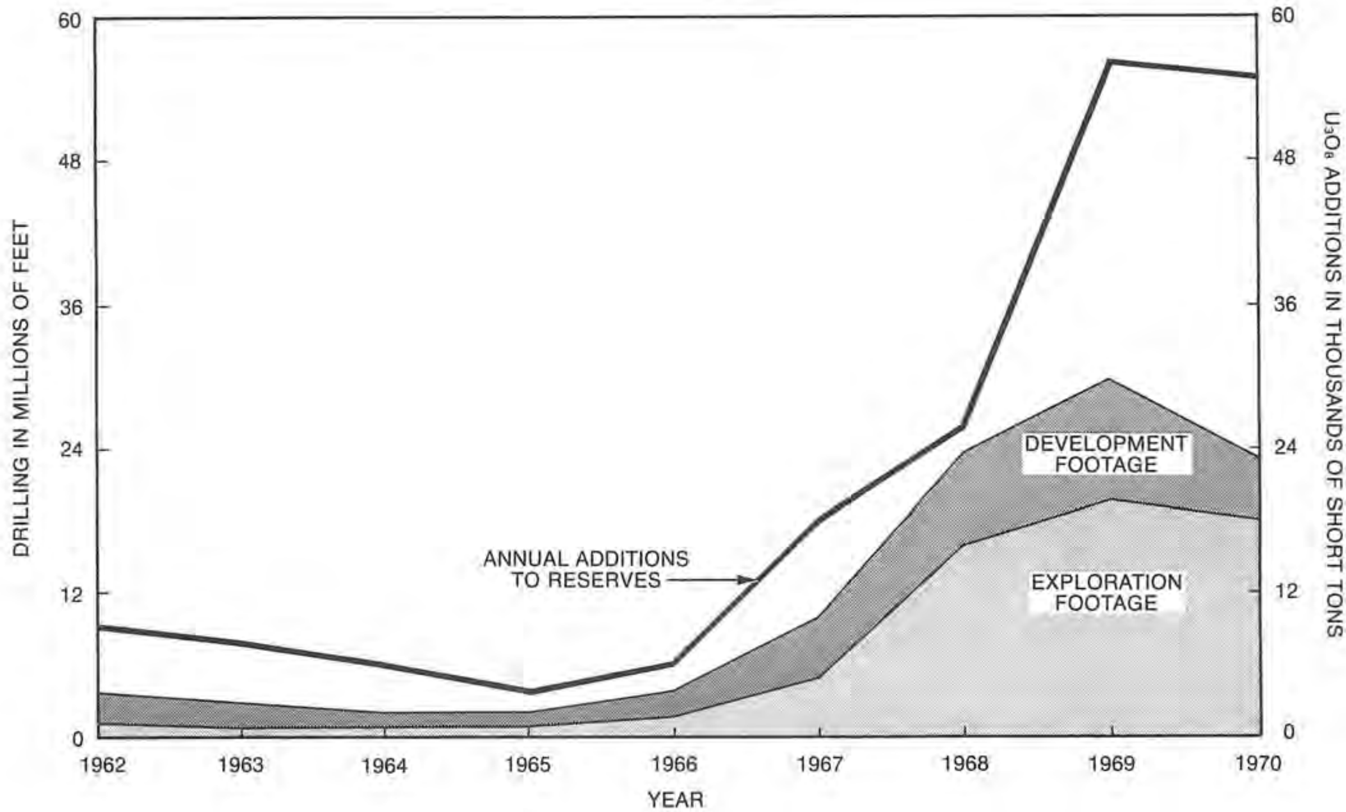

Figure 17. Reserve Additions and Exploration and Development Drilling.

Table XCIII reflects the latest ENEA-IAEA estimate of resources up to $15 per pound of U_3O_8 as of January 1970,* adjusted as indicated in the accompanying footnotes. This table includes the January 1, 1971, USAEC domestic reserve estimate. Uranium reserves (reasonably assured resources) are known with reasonable precision, and projections of potential resources (estimated additional resources) have been developed with reliable backup data.† Because prospecting has been directed principally toward finding uranium which can be sold for less than $10 a pound, the reliability of estimates for these resources is higher than for higher-cost deposits.

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*European Nuclear Energy Agency--International Atomic Energy Agency, *Uranium Resources, Production and Demand* (Paris, September 1970).

†*Reasonably assured resources* refers to uranium which occurs in known ore deposits of such grade, quantity and configuration that it can, within the given price range, be profitably recovered with currently proved mining and processing technology. Estimates of tonnage and grade are based on specific sample data and measurements of the deposits and on knowledge of ore-body habit. Reasonably assured resources in the price category of below $10 per pound are equivalent to *reserves* in the mining sense.

Estimated additional resources refers to uranium surmised to occur in unexplored extensions of known deposits or in undiscovered deposits in known uranium districts, and which is expected to be discoverable and economically exploitable in the given price range. The tonnage and grade of estimated additional resources are based primarily on knowledge of the characteristics of deposits within the same districts.

TABLE XCIII

NON-COMMUNIST WORLD RESOURCES OF URANIUM IN 1970
(U_3O_8 in Thousands of Tons)

	Reasonably Assured*	Estimated Additional*	Total Resources
Price to $10 per Pound			
Canada	232	230	462
South Africa	200	15	215
France, Niger, Gabon, C.A.R.†	95	81	176
Other‡	63	49	112
United States§	390	680	1,070
$10 Subtotal	980	1,055	2,035
South West Africa & Australia ‖	100	200	300
$10 Subtotal	1,080	1,255	2,335
Price $10-$15 per Pound#			
Canada	130	170	300
South Africa	65	35	100
France, Niger, Gabon, C.A.R.†	22	35	57
Other	43	70	113
United States	190	360	550
$10-$15 Subtotal	450	670	1,120
Less-than-$15 Total	1,530	1,925	3,455

* See second footnote, p. 151, for definition.

† Central African Republic.

‡ Argentina, Australia, Brazil, Italy, Japan, Mexico, Portugal, Spain.

§ According to USAEC estimates of January 1, 1971, some 90,000 tons of U_3O_8 may occur as a by-product of phosphate and copper production through year 2000; 25,000 might be available by 1985.

‖ The task group decided it would be desirable to recognize recent reported discoveries in South West Africa and Australia. In the absence of specific data, the task group arbitrarily added 100,000 reasonably assured and 200,000 estimated additional for these discoveries.

\# Excludes reasonably assured of 350,000 tons and estimated additional of 50,000 tons for Sweden considered to be essentially unavailable because of production limitation and stated Swedish policy of meeting only a "certain part" of Swedish requirements.

Six countries--The United States, Canada, South Africa, South West Africa, Australia and France (together with its former colonies of Niger, Gabon and the Central African Republic)--have 94 percent of the reasonably assured resources and 96 percent of the estimated additional resources at $10 a pound of U_3O_8. These countries also have 93 percent of the total reasonably assured and estimated additional resources up to $15 per pound of U_3O_8.

It should be noted that the likely rate of production of uranium reserves is limited in some areas by such factors as size and distribution of deposits

(Canada) and association with other types of mining operations (South Africa). Considering the problems and proposed operational rates, it is estimated that not over 800,000 tons of presently delineated reasonably assured reserves (U_3O_8 at $10 or less per pound) could be produced over the 15-year period. However, the required additional U_3O_8 will be available from additional deposits delineated as reasonably assured reserves by continuing exploration and development.

Non-Communist uranium resources at $15 to $30 per pound of U_3O_8 have been estimated by ENEA-IAEA at 560,000 tons reasonably assured and 1,580,000 tons estimated additional. Higher-cost categories of U_3O_8 have not been estimated on a worldwide basis, but they represent virtually an inexhaustible supply of uranium if used to fuel breeder reactors which, because they use essentially all of the uranium (U_{235} and U_{238}), can economically use such high-cost fuel. The U.S. Atomic Energy Commission's current estimate of U.S. reasonably assured and estimated additional resources up to $100 per pound is 17 million tons of U_3O_8.

CAPITAL REQUIREMENTS

It is estimated that a capital investment of $4.9 billion will be required for exploration in the United States and for providing necessary facilities for the domestic mining, milling, refining and conversion, enriching, fabricating and reprocessing of uranium for use as fuel in nuclear power plants during the period 1971-1985.

In assessing the significance of these capital requirements, two factors should be considered: (1) the uniqueness of the nuclear fuel cycle and the newness of the technology involved in comparison with fuel forms for fossil-fueled plants and, consequently, the relatively greater opportunities for improving nuclear fuel cycle, and (2) the somewhat larger investment in nuclear generating plant facilities than in comparable fossil-fueled plants.

Delineating the capital investment requirements between the fuel supply facilities and the generating plant facilities is easier and more meaningful in the case of fossil-fuel fired plants than in the case of nuclear electric generating plants. Because only a portion of the nuclear fuel is expended during a core exposure, it is necessary to reclaim the unused nuclear fuel. This reprocessing procedure, including transport equipment, which will require a capital investment of $350 million, is not required in the fuel cycle for the fossil-fuel fired plants. Consequently, direct comparison is difficult. Furthermore, the burnup charge and investment charge on the core while it resides in the reactor, though not a capital investment charge for fuel facilities, represents a significant portion of the total nuclear fuel cycle cost.

The $4.9 billion in new capital investment required for the total nuclear fuel cycle in the United States to provide domestic nuclear fuel represents an investment of $16.71 per KW for the 292,500 MWe of nuclear electric power generating capacity, projected to be required during the years 1971-1985, inclusive, to utilize this fuel. For that portion of the fuel cycle which includes exploration, development, mining and milling, the capital investment required for the initial appraisal is estimated to be about $2.1 billion or $7 per KW.

While approximately $5 billion is a significant investment, it is much smaller than the investment which will be required for the related electric generating facilities. Thus it would appear that the major capital investment decision will be made by the user rather than the supplier.

A summary of the several categories of projected capital investment is as follows:

CATEGORY	EXPENDITURE (In Millions of $)
Exploration and Development*	880
Mining and Milling†	1,229
Refining and UF_6 Conversion	140
Enrichment‡	1,980
Fuel Fabrication	310
Fuel Recovery§	350
TOTAL	$ 4,889

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* Estimate for exploration and development is conservative since it is based on maintaining an 8-year forward reserve in 1985 equal to 8 times the 1985 requirements for U_3O_8 whereas post-1985 annual uranium requirements might require an additional 200,000 to 300,000 tons of reserve. AEC stock (50,000 tons of U_3O_8) is assumed to be available to meet a portion of 1985 forward reserve requirements.

† The sum of the first two items ($2,109 million) is equivalent to a capital investment for exploration, development, mining and milling of $2.34 per pound of U_3O_8 based on 900 million pounds (450,000 tons) of U_3O_8. These capital cost estimates do not include the cost of acquisition of mining properties.

‡ Estimate includes cost for improving and updating present enrichment plant complex (gaseous diffusion plant [GDP]) and for adding new enrichment capacity. Because capital investment to supply required additional electric power will be made by the utility industry, it is not included in this estimated figure.

§ Includes cost of equipment to transport spent fuel from reactor site to reprocessing plant. However, additional capital investment for off-site nuclear storage is not included. Because there is a 10-year lag between taking delivery of irradiated fuel and the disposal of waste fission products, additional capital investment for such storage is not believed to be significant prior to 1985.

Chapter Eleven

Oil Shale Task Group

Summary of Report

OIL SHALE TASK GROUP

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OIL SHALE TASK GROUP REPORT

ABSTRACT

Synthetic crude petroleum from oil shale does have potential during the period 1971-1985 which, given the size and trend of energy needs, is worth careful consideration. However, under the conditions presumed to exist for the initial appraisal, the projected utilization of this resource is limited to 100 MB/CD by 1985, even though there are 20 billion barrels of recoverable oil shale reserves having primary commercial attraction.

There are several major factors which underlie this projection and which affect the future of oil shale:

- Oil shales do not contain oil as such, but organic matter called kerogen, which can be converted into crude shale oil, gas and carbonaceous residue by heating. Thus, within present technology, a complex system is required to mine and retort the oil shale and to upgrade the crude shale oil to synthetic crude oil (syncrude).

- The only oil shale deposit in the United States having adequate size and availability for potential commercial utilization at the present time is the Green River Formation, underlying 16,000 square miles of several basins in Colorado, Utah and Wyoming. This formation contains an estimated 1.8 trillion barrels of shale oil, but except for about 5 percent of the formation, the deposits are largely speculative because they are low grade or deeply buried and poorly defined.

- Early interest is assumed to center on zones of oil shale at least 30 feet thick and yielding at least 30 gallons per ton. For purposes of the initial appraisal, only a more restrictive cut of these zones averaging 35 gallons per ton (Class 1 Reserves) was considered to be reasonably prospective.

- Reserves will be recoverable mainly by underground mining, and these will average only 60 percent of in-place resources.

- Under the assumed conditions, oil shale reserves are estimated to be the equivalent of 20 billion barrels of oil, but only 6 billion barrels are on private lands and subject to immediate development.

- Technology is presently available (although subject to continuing improvement) for mining the oil shale and is well along in development for converting the kerogen to a crude oil and upgrading the crude shale oil to a high-quality syncrude.

- It has been assumed, for this projection, that environmental concerns will be resolved and will not present a deterrent to oil shale development.

- It has been assumed also, for this projection, that adequate water is available to support oil shale operations and that use of water for this purpose will be permitted.

- No attempt has been made to identify the programs and investments necessary to develop the infra-structure (community facilities, roads, etc.) in Colorado to support a viable oil shale industry.

- Based on the above assumptions and using 1970 dollars, capital investment in facilities to produce 100 MB/CD of syncrude from oil shale will be on the order of $500 million.

- Syncrude value at the upgrading plant in Colorado is projected to be within the range of $4 to $5 per barrel--depending on the assumptions used regarding return on investment, the development schedule for production and other key parameters.

- On the assumption that no federal leases will be available, production of the syncrude from oil shale reserves on private lands is expected to be limited to 100 MB/CD by 1985, even providing that economics and environmental attitudes were favorable.

- Under more favorable conditions, production of syncrude from oil shale reserves is projected to reach a maximum of about 400 MB/CD, but this development would be unlikely without the leasing of federal lands. The *potential* production could be somewhat higher.

SUMMARY OF OIL SHALE TASK GROUP REPORT

ENERGY RESERVES IN U.S. OIL SHALE

1. *Geography and Geology*

Although oil shale deposits are found in numerous areas of the United States, the only deposit of adequate size and availability to have potential commercial value at the present time is the Green River Formation of Eocene Age. This formation ranges in thickness from a few hundred to about 7,000 feet, underlying 16,000 square miles of several basin areas in Colorado, Utah and Wyoming. Location of thick deposits, mainly dolomitic shales and marlstones, is shown in Figure 18. In general, the central parts of the Piceance Basin in Colorado and Uinta Basin in Utah and Colorado contain thick, rich oil shale sequences which grade to thinner and leaner oil shale at the basin margins. Somewhat thinner and generally lower-grade deposits in the Green River and Washakie Basins, Wyoming, also show decrease in grade toward the basin margins.

2. *Estimate of Energy Available*

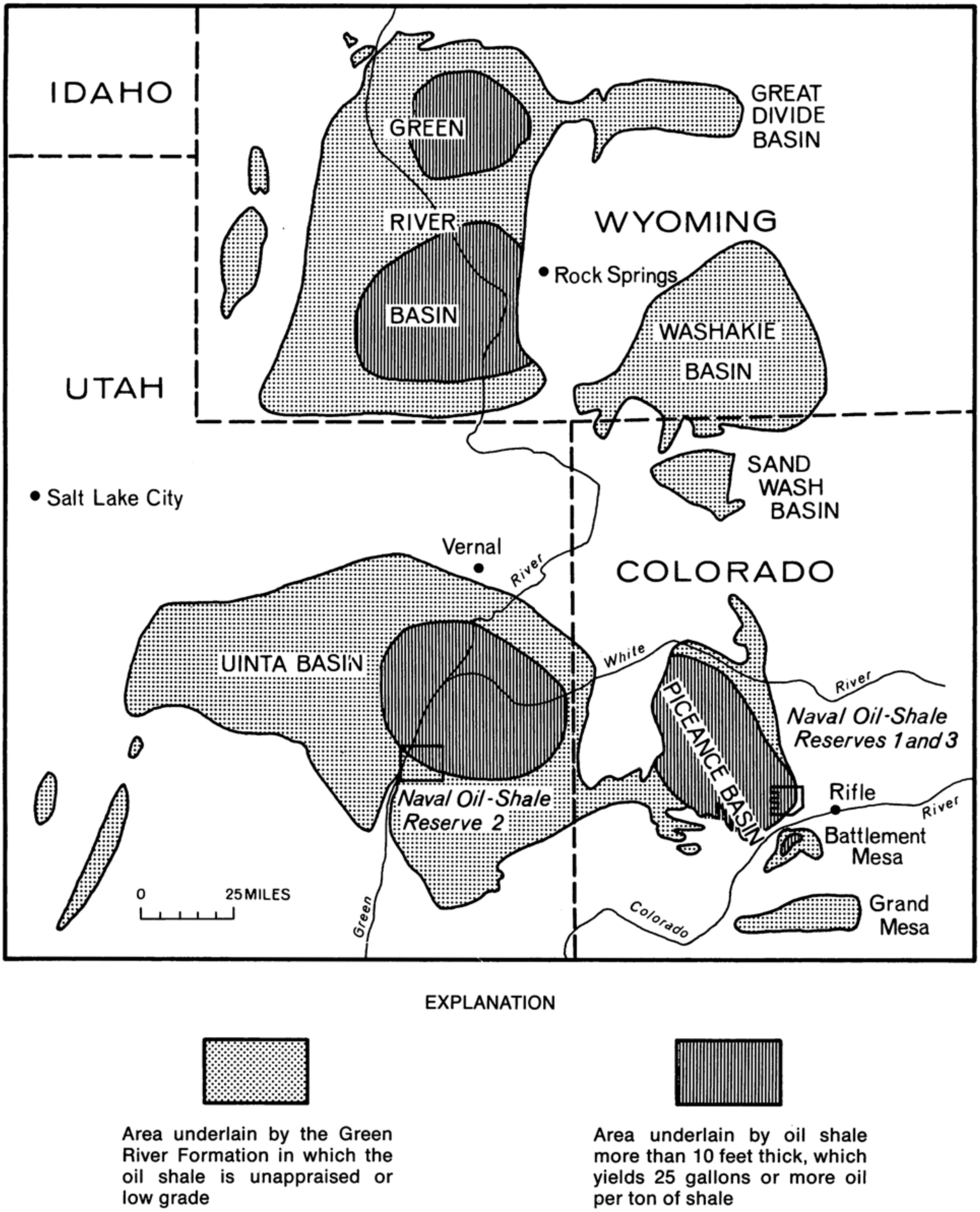
In the initial appraisal the existing work and literature on oil shale resources were surveyed and interpreted in light of the reserves which may be recoverable at varying degrees of commercial attractiveness.

Basic assumptions underlying the resource and reserve estimates are:

- Only the Green River Formation shales are commercially attractive.

- Reserves will average 60 percent of the in-place resources and will be recoverable mainly by underground mining.

- Early interest will center on zones at least 30 feet thick and yielding at least 30 gallons of oil per ton of shale.



Source: Geological Survey Circular 523

Figure 18. Distribution of Oil Shale in the Green River Formation, Colorado, Utah and Wyoming.

a. Resources

For purposes of this analysis, the oil shale resources (in-place) were arranged in four groupings. These general classifications are intended to reflect the degree of commercial attractiveness and are explained below:

Class	Description
1,2	In total, these are the resources satisfying the basic assumption that early interest will be limited to deposits at least 30 feet thick and averaging 30 gallons per ton of shale. Only the most accessible and best defined deposits are included. Class 1 is a more restrictive cut of these reserves and indicates that portion which would average 35 gallons per ton over a continuous interval of at least 30 feet.
3	These are resources which, although matching Classes 1 and 2 in richness, are more poorly defined and not as favorably located. They may be considered potential resources and would be exploitation targets at the exhaustion of Class 1 and Class 2 resources.
4	Class 4 resources are lower grade, poorly defined deposits ranging down to 15 gallons per ton which, although not of current commercial interest, represent a target in the event that their recovery becomes feasible. These may be considered speculative resources.

The richness of the Mahogany zone in the Piceance Basin allows a distinction between Class 1 and Class 2 resources. As part of this appraisal, the resources averaging 35 gallons per ton over a minimum 30-foot section were determined from available assay data from Mahogany core tests. These are termed Class 1 resources and are estimated at 34 billion barrels. The remaining estimated 83-billion-barrel Piceance Basin Mahogany resources are designated Class 2. In the Uinta Basin, 12 billion barrels of Class 2 resources have been estimated.

b. Reserves

For the purpose of this report, reserves are the resources available for processing after mining and as assayed by the Modified Fischer Assay method.

If it is assumed that essentially all the mineable resources will be recovered by underground mining, then providing for pillars, barriers between mines and unforeseen contingencies reasonably leads to the conclusion that an average of 60 percent of the resources will be recoverable and that this quantity can therefore be classified as reserves. Reserves are calculated for Class 1 through Class 3 resources only. Class 4 resources appear mainly speculative and, at this time, do not merit consideration as reserves before the year 2000. Both estimated resources and reserves (at 60-percent recovery of resources) are summarized in Table XCIV.

Attention is called to the fact that only about 10 percent of the total oil shale resources shown in Table XCIV are classified as reserves and that only about 10 percent of these total reserves are currently considered reasonably prospective before 1985. Of the 20 billion barrels in this latter, Class 1 reserve category, it will be noted in the following section that only the fraction situated on private lands is presently available for development. Of these private lands, a substantial portion need land exchanges with adjacent federal holdings to improve workable developments.

TABLE XCIV

SUMMARY OF OIL SHALE RESOURCES AND RESERVES
GREEN RIVER FORMATION - COLORADO, UTAH AND WYOMING
(Billions of Barrels)

Location	Resources					Reserves @ 60% Recovery			
	Class 1	Class 2	Class 3	Class 4	Total	Class 1	Class 2	Class 3	Total
Piceance Basin									
Colorado	34	83	167	916	1,200	20	50	100	170
Uinta Basin									
Colorado & Utah	--	12	15	294	321	--	7	9	16
Wyoming	--	--	4	256	260	--	--	2	2
TOTAL	34	95	186	1,466	1,781	20	57	111	188

An estimate of the ownership division of the Class 1 and Class 2 reserves is provided as follows:

Ownership	Reserves at 60% Recovery (Billions of Barrels) Class 1 only	Class 1 + Class 2
Private Lands	6	17
Federal Lands--Clear Title	7	37
Federal Lands--Clouded Title*	5	20
Federal Lands--Naval Reserve	2	3
TOTAL	20	77

* Federal lands with clouded title reflect only pre-1920 unpatented claims.

This shows that the main segments of reserves are located on federally owned lands. It is clear, therefore, that the development of the largest amount of the Nation's oil shale reserve awaits the issuance of a federal leasing policy plus the resolution of title questions on significant parts of the federal lands. Such a policy would serve to reduce some of the present uncertainties. However, questions relating to process operability and project economics must also be answered to the satisfaction of those who will make the investment decisions.

MINING AND CRUSHING OIL SHALE WITH PRESENT-DAY TECHNOLOGY

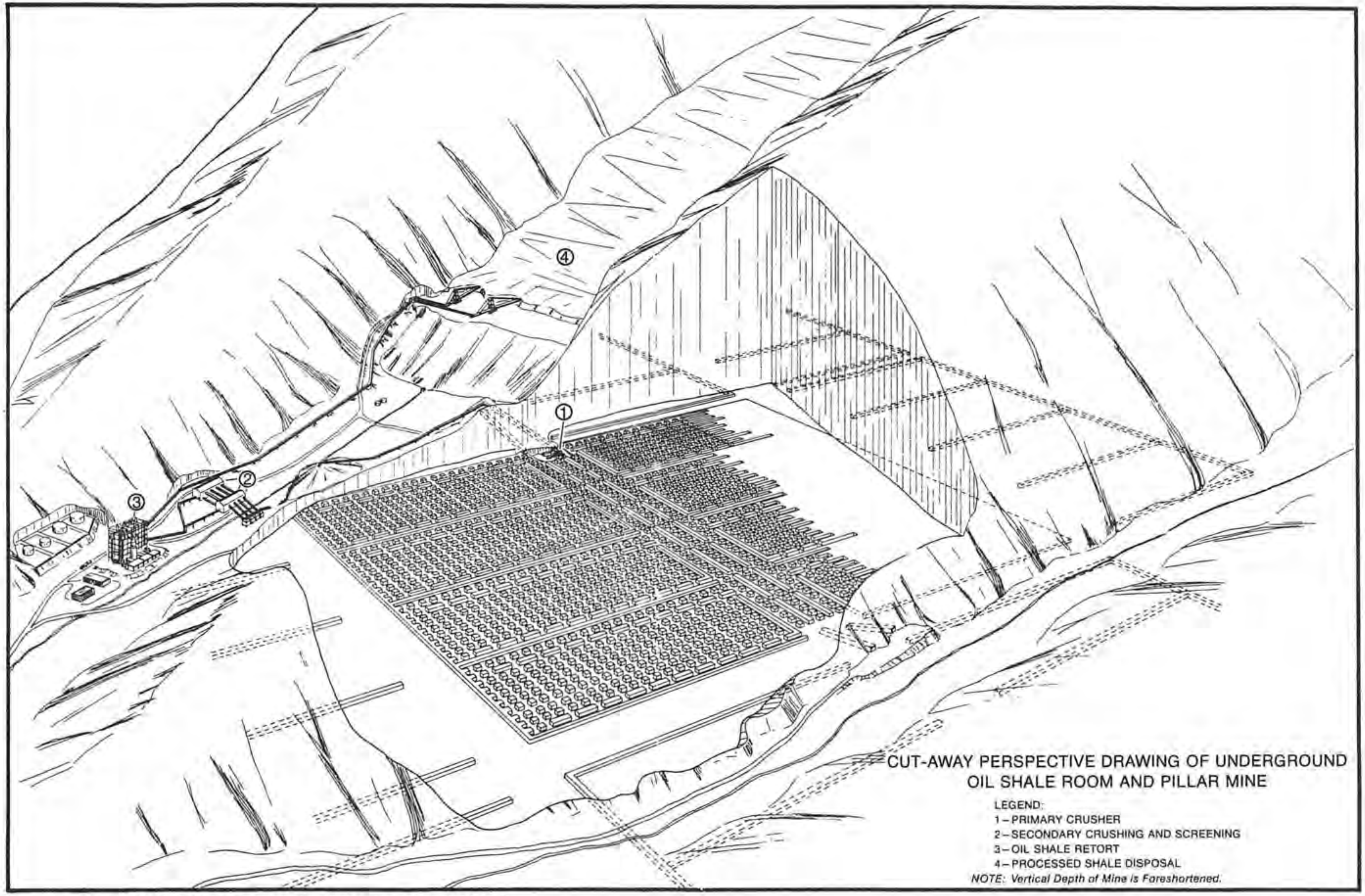
1. Mining Methods and Limitations

This initial appraisal has considered both underground and surface methods of mining oil shale in the Piceance Creek Basin of Colorado and the Uinta Basin of Colorado and Utah. Though subject to continuing improvement, adequate technology is available for mining the oil shale. However, the task group projected that, under the conditions of this appraisal, only the higher quality Class 1 resources would be developed. The most practical method for recovery of these resources is by underground mining, using the room-and-pillar method illustrated in Figure 19.

Since large reserves are available, underground mining is restricted in this appraisal to a 30- to 90-foot thickness of shales containing 30 gallons per ton or more of oil and which are situated in the Mahogany zone of the Parachute Creek member of the Green River Formation. It is also confined to that portion of the Mahogany zone that is approximately 1,500 feet or less below the surface.

Underground mining of such deposits permits the use of large equipment, much of it similar or identical to that employed in surface mining. Mine dimensions such as 50- to 60-foot room widths and 30- to 90-foot mining heights will allow the use of multimachine drill jumbos, 15- to 20-cubic-yard capacity or larger front-end loaders, and 100-ton capacity or larger trucks hauling to a primary crusher.

Mine access by adit (side-hill horizontal entrance) within a producing horizon is most likely at points where the shale horizon outcrops at the surface, and tunneling from the outcrop can achieve lower costs than sinking a shaft. In considering the topography of the higher quality shale lands presently available for development, it is anticipated that adit mines will be the



Source: *Report on Economics of Environmental Protection for a Federal Oil Shale Leasing Program*, State of Colorado, January 1, 1971.

Figure 19. Underground Mining of Oil Shale.

first producers of oil shale and probably will provide the bulk of production during the early phases of the oil shale industry.

Previous studies indicate that 65- to 70-percent recovery can be expected from a room-and-pillar method of underground mining that considers an average mining height of 60 feet (30 to 90 feet) and that is not overlain by more than 1,500 feet of overburden. Additional pillars, required along outcrops, between mines, and to protect shaft or adit and plant locations and drainage systems, may reduce overall recovery to about 60 percent. Moderate variations in percentage recovery will have only minor effects on mining cost.

2. Preparation of Shale for Retorting (Crushing and Screening)

Oil shale is not extremely hard and can be drilled and blasted efficiently, but the abrasiveness and unusually high resiliency of the rock present special difficulties for crushing and screening. Large primary crushers will be required to handle both the volume of material and the large chunks inherent in mine-run shale. Crushing of shale produces much dust, and any proposed oil shale crushing plant, either on the surface or underground, must include an effective system of dust suppression.

The type of retort assumed for this initial appraisal requires feed crushed to minus 0.5-inch size, rather than 2- to 3-inch dimensions, as for other types. The additional expense of crushing and screening to the finer size is included in the estimated cost for this study. The increased cost is partially offset by complete utilization of the crushed product as well as greater shale oil recovery.

3. Capital and Operating Costs of Mining

Capital and operating costs were developed from previously published information with adjustments made to mid-year 1970. A production rate of about 23 million tons per year per mine was assumed. At this high rate, minor variations in production will have little effect on unit costs.

For syncrude production at an assumed level of 100 MB/CD, two mines are presumed to be utilized with each having a capacity of 62,400 tons per calendar day or 23 million tons per year. The resultant total capital requirements for underground mining (utilizing an adit entrance), crushing the raw shale to minus 0.5-inch size, and disposing of the shale residue are as follows:

	Capital Costs (Millions of $)	
Operation	Initial Investment	Deferred Investment
Mining	51.0	31.8
Crushing	21.0	1.6
Shale Residue Disposal	3.0	17.6
TOTAL	75.0	51.0
Unit Investment Cost--Dollars per Daily Ton of Capacity	601	409

Included in the $51 million initial mining investment is $6.4 million of preproduction mine development cost. This has been capitalized but might instead be treated as an operating expense. Initial investment is presumed to take place during the construction period of the project. Deferred investment occurs throughout the first 18 years of the 20-year project life. Unit investment costs have been calculated on the basis of tons of shale mined per calendar day.

Annual operating costs--including labor, supplies, utilities and overhead, but not including depreciation, interest and profit--are calculated to be:

	Operating Costs (Millions of $ per Year)
Mining	17.8
Crushing	6.0
Shale Residue Disposal	4.4
TOTAL	28.2

This amounts to an estimated unit operating cost for the combined operations of 62¢ per ton of shale mined.

RETORTING OIL SHALE TO PRODUCE CRUDE SHALE OIL

1. *Review of Retorting Processes*

Technology for this phase of a shale oil operation is well along the way to being developed, but varying processes are still under trial. In any case, to convert the organic material in oil shale into oil and gas, generally the shale is heated to about 900° F. The conversion efficiency may be related to the Fischer assay by giving retorted oil yield as a percent of the assay oil yield from a sample of the same shale.

In general, retorting heat requirements can readily be met by the combustion of the coke-like residue on the spent shale, the recovery of heat from the spent shale or ash, or the burning of retort gas. Approximately 600,000 to 800,000 BTU's are required to retort 1 ton of oil shale. Since this amount of heat must be transferred from hot gases or solids, the heat transfer problem is relatively large.

Because of the importance of heat transfer in the retorting of oil shale, the heat transfer techniques used by the different processes serve as a good means of classification. Retorting processes that have been reviewed in detail in the initial appraisal are grouped as follows:

Direct heating by hot gases from combustion within the retorting vessel:

Bureau of Mines Gas Combustion
DEI Kiln (Development Engineering Inc.)
Union Oil Company of California Retort "A"

Heat transfer from an externally heated carrier fluid:

Cameron and Jones Vertical Kiln (Petrosix Process)
DEI Kiln (alternate method of operation)
Union Oil Company of California Retort "B"

Heat transfer from recycled hot solids:

TOSCO Process (The Oil Shale Corp.)
Lurgi-Ruhrgas Process

Published information regarding the maximum capacity of retorts operated to date and their oil yield efficiencies is summarized below:

Name of Process	Maximum Size (Tons/Day)	Efficiency Percent of Assay
Gas Combustion (B of M)	360	82-87
Union Retort "A"	1,200	Not reported
Union Retort "B"	(Bench-scale)	92
TOSCO	1,000	106
Lurgi-Ruhrgas	16	100+

Data on operation of the DEI Kiln and the Cameron and Jones Vertical Kiln as oil shale retorts are not yet available. Essentially, these are modifications of the Bureau of Mines Gas Combustion retort. Their efficiencies may be considered at least as high as those given for other retorts of the same type.

2. Representative Product Yields and Properties

The retorting method utilizing hot recycled solids has been selected for this report as representative of a commercial operation.

A commercial yield of C_4-plus crude shale oil amounting to 100 volume percent of Fischer assay is considered a good assumption for the present study. Estimated properties of the crude shale oil are compared with those of the syncrude on the next page.

3. Disposal of Solid Residue

The most immediate problem with respect to disposal of the shale residue from a retorting operation is to find a place to put the material. Because of increase in bulk, the mine cannot accommodate all of the residue and at least a significant portion will have to be disposed of above ground. For example, to produce 100 MB/CD of syncrude requires the daily disposal of residue equivalent to about one foot in depth covering an area of 40 acres.

With respect to aboveground disposal, attention and study are being given to development of a mechanically stable dump, prevention of major water flow or seepage through the solids, prevention of excessive blowing of dust during or after deposition of the solids and development of plant cover on the dump.

4. Capital and Operating Costs for Retorting

The following retorting capital and operating costs include recovery of butanes and heavier hydrocarbons from the retort gas and pipelining of the gas to the upgrading facilities for fuel and process use. The time basis is mid-year 1970.

The estimated capital cost for retorting, used in this report, is $1,420 per ton per calendar day of retort capacity. This cost includes a paid-up process royalty.

Estimated operating costs (not including depreciation and income taxes) are 32¢ per ton of shale retorted during the first 15 years and 40¢ per ton during subsequent years. The additional cost for later years provides for increased maintenance.

UPGRADING CRUDE SHALE OIL TO SYNCRUDE

Shale oil from retorting (called crude shale oil) has some unusual characteristics but it is similar in many respects to conventional crude oil. Upgrading is necessary because shale oil contains an unusually high concentration of nitrogen compounds and these compounds deactivate catalysts used in many petroleum refining processes, including catalytic cracking, hydrocracking and reforming. The oil also has high pour point and viscosity which need to be reduced to facilitate handling in pipelines. Crude shale oil can be accepted for processing by conventional techniques, although the hydrogenation severity is somewhat greater than normally required.

1. Description of the Process Flow Scheme

Figure 20 illustrates one scheme which has been shown to be readily applicable to a typical crude shale oil and which was selected for this report. The crude shale oil is distilled into separate streams of gas, naphtha, light oil, heavy oil and residuum. The residuum is subjected to delayed coking, with production of coke, oil and gas.

The light oil plus naphtha and the heavy oil streams are catalytically hydrogenated in separate reactor systems. Naphtha and light oil produced during hydrogenation of the heavy oil are separated and charged to the light oil hydrogenation unit for more complete nitrogen removal. Ammonia and hydrogen sulfide are recovered and treated for sale as by-products. Hydrogen required in the process is manufactured by steam reforming of the gas produced.

2. Representative Products and Yields

Typical properties of the crude shale oil and syncrude are:

	Crude Shale Oil	Syncrude
Gravity, °API	28.0	46.2
Pour Point, °F	75	50
Sulfur, wt %	0.8	0.005
Nitrogen, wt %	1.7	0.035
RVP, psi	--	8.0
Viscosity, SUS at 100°F	120	40
Analysis of Fractions		
Butanes and Butenes, vol %	4.6	9.0
C_5-350°F Naphtha		
Vol %	19.1	27.5
Gravity, °API	50.0	54.5
Sulfur, wt %	0.70	<0.0001
Nitrogen, wt %	0.75	0.0001
350-550°F Distillate		
Vol %	17.3	41.0
Gravity, °API	31.0	38.3
Sulfur, wt %	0.80	0.0008
Nitrogen, wt %	1.35	0.0075
550-850°F Distillate		
Vol %	33.0	22.5
Gravity, °API	21.0	33.1
Sulfur, wt %	0.80	<0.01
Nitrogen, wt %	1.90	0.12
850°F-Plus Residue		
Vol %	26.0	None
Gravity, °API	12.0	--
Sulfur, wt %	1.0	--
Nitrogen, wt %	2.4	--

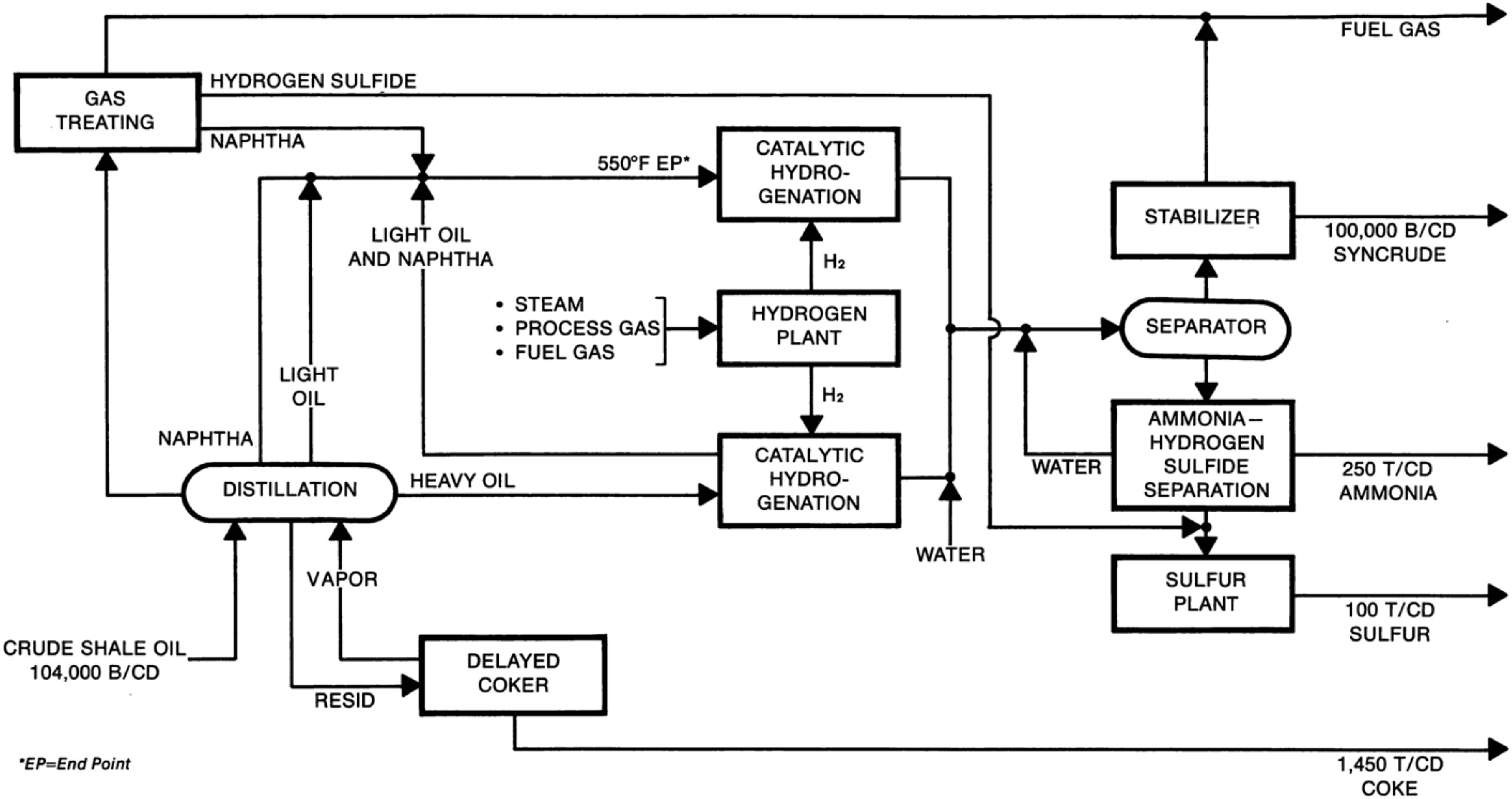


Figure 20. Flow Diagram for Upgrading Crude Shale Oil.

Estimated oil yields used in the present report are, respectively, 100 percent of C_4-plus crude shale oil and 96 percent of C_4-plus syncrude, expressed as volume percent of the oil produced from the raw shale by the Modified Fischer Assay method. These yields are equivalent to 0.83 B crude oil or 0.80 B syncrude per ton of shale assaying 35 gallons per ton.

3. *Capital and Operating Costs for Upgrading*

Investment in upgrading facilities to produce 100 MB/CD of finished syncrude using the scheme shown in Figure 20 is estimated to total $193 million. Process royalties and off-site costs are included.

Operating cost for these facilities is estimated to be 44¢ per barrel of crude shale oil feed. This includes labor, power, maintenance, catalyst and chemicals, property taxes and insurance, plant overhead and corporate overhead. At the end of the depreciation period of 15 years the cost is estimated to increase to 51¢ per barrel due to increased maintenance.

BY-PRODUCTS AND FUEL

The yield of by-products from producing 100 MB/CD of syncrude and their assigned values are as follows:

By-product	Yield	Value
Anhydrous Ammonia	250 tons	$30/ton
Sulfur	100 long tons	$15/long ton
Green Coke	1,450 tons	$4/ton

Essentially, the gas produced is sufficient to supply plant fuel and hydrogen plant process feed. The total electric power for the project could be generated from burning the green coke produced. Thus the net production of energy from oil shale is all in the form of syncrude.

ECONOMICS OF SHALE OIL PRODUCTION

1. *Discounted Cash-Flow Rate of Return*

The discounted cash-flow rate of return method was used to obtain the relationship of syncrude value to rate of return on the entire project. Bases for the calculations are as follows:

- 3-year construction period
- 20-year operating period
- 3-month startup period during the first year of operation, when no product is credited
- 52.0-percent U.S. and state income tax rate
- 0.0-investment tax credit
- 15.0-percent depletion allowance, based on the value of the retort products.

2. *Estimation of Probable Range in Syncrude Value*

A commercial venture sized to produce 100 MB/CD of syncrude includes two mines and two retorting plants, each having a capacity of 62,400 tons per calendar day of oil shale. The combined 104 MB/CD of crude shale oil would be upgraded in a single plant.

Variations in investment estimates were made to obtain a range of syncrude values by underground adit mining of 35 gallon per ton shale. Four cases studied are given below:

	Case (Millions of Dollars)			
	A	B	C	D
Total Investment	503	442	414	557
Working Capital	21	21	21	21
Total Capital	$524	$463	$435	$578

Case A is the base case from which variations were made. It contains a 25-percent contingency in the retorting and upgrading investment. Case B investment was changed by reducing this contingency to 10 percent and by making a proportionate reduction in mining capital. A further reduction in mining capital was made in Case C by assuming significant technological advances in mining and crushing, although there are no known projects which make such advances likely. A 30-percent higher retorting capital cost was used in Case D than in Case A because of potential problems regarding onstream efficiency and removal of dust from the oil and gas.

A series of curves was derived which relates syncrude value to the discounted cash-flow rate of return (see Figure 21). These curves indicate, for example, that if a 15-percent return is assumed, the range in syncrude value at the upgrading plant in Colorado would be $4.35 to $5.30 per barrel.

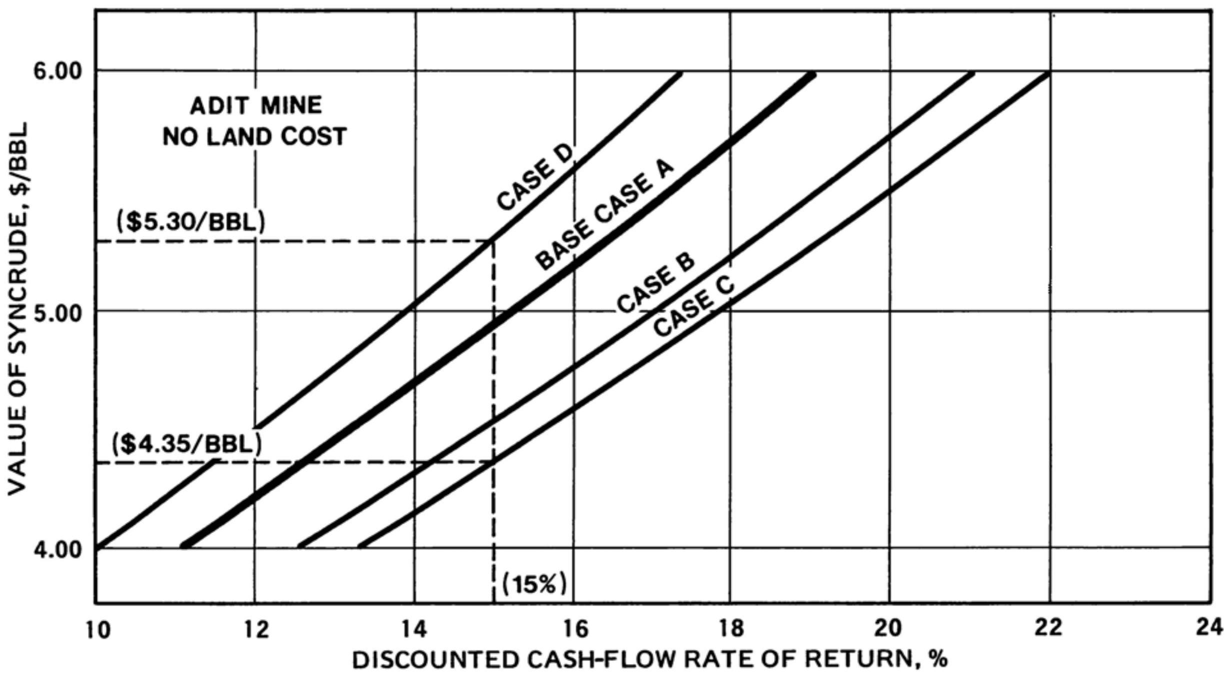


Figure 21. Value of Syncrude from 35-Gallon/Ton Oil Shale.

A tentative development schedule for production of syncrude from oil shale has been worked out. It assumes that the value placed on the syncrude is high enough to encourage private companies to engage in this operation.

The syncrude production schedule in Figure 22 shows the results of the development schedule. All of this oil would be produced in PAD District IV. Projected production rates in both volume and heating value of syncrude are as follows:

Years	MB/CD	Trillions of BTU's per Year
1978 through mid-year 1981	100	197
Mid-year 1981 through 1983	200	394
1984-1985	400	788

With regard to the above tentative production schedule, particular attention is called to the note on Figure 22:

> Assuming a favorable attitude regarding the environment and the necessary community development to assure the necessary manpower supply, this is the potential development rate with the number of companies holding sufficient reserves and the capital requirement placed upon them.

Furthermore, under the conditions assumed to prevail for the base case--i.e., minimal changes from policies, practices and economic climate existing at the beginning of the study period--only a token volume of syncrude from oil shale is projected to be developed from private lands and only one 100 MB/CD plant is expected to be operating by 1985.

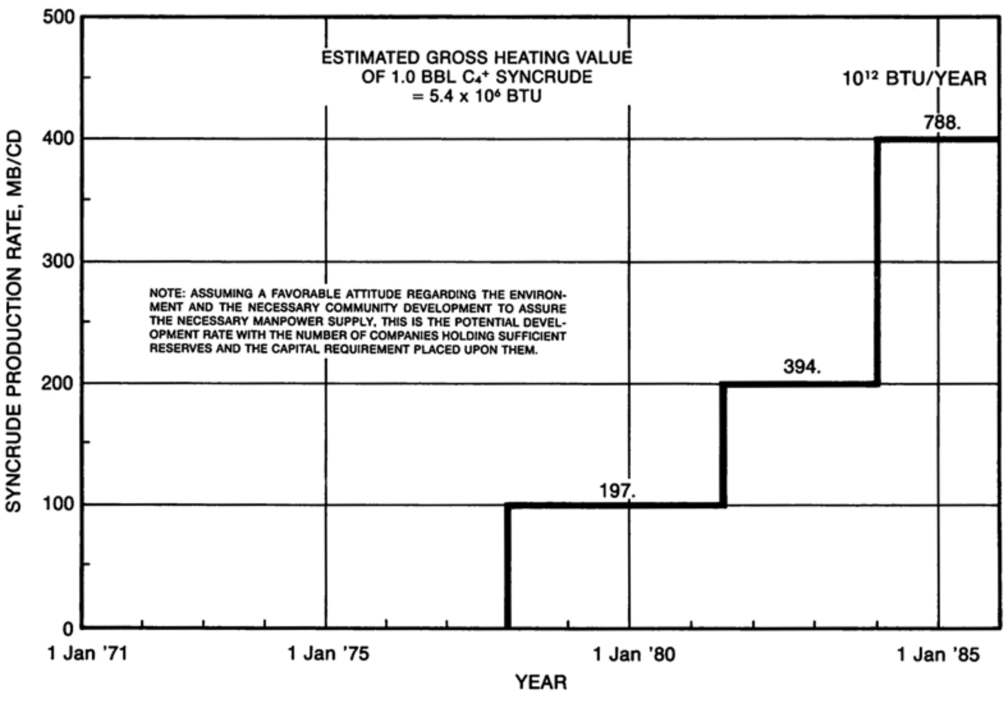


Figure 22. Production Schedule of Syncrude from Oil Shale--Initial Appraisal.

Chapter Twelve

Tar Sands Task Group

Summary of Report

TAR SANDS TASK GROUP

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TAR SANDS TASK GROUP REPORT

ABSTRACT

Under the conditions assumed to prevail for the initial appraisal, it is estimated that only a relatively small contribution to total energy needs will be made from tar sands: probably half a million to a million and a quarter B/D by 1985, and this almost wholly from Canadian sources. Factors affecting this projection are:

- The largest known tar sands deposits are in Canada, Venezuela and (possibly) Colombia. Eastern Hemisphere and United States deposits are much smaller. Athabasca and other deposits in Alberta, Canada, are estimated to contain 399 billion barrels of in-place bitumen subject to recovery, which could yield 174 billion barrels of synthetic crude. The Alberta sands will be the primary and probably the only source of commercial production of tar sands oil for North American markets through 1985.

- Recovery of bitumen by mining and hot water extraction of the Athabasca sands is currently being practiced. Overall recoveries of about 70 percent of in-place bitumen are possible with this method, which is applicable to sands covered by up to about 100 to 150 feet of overburden.

- Recovery of bitumen via *in situ* treatment of deep-lying deposits has been studied by a number of companies, and further development work is under way or planned. Overall recovery by *in situ* techniques will probably be in the range of 35 to 50 percent of in-place reserves.

- Bitumen upgrading by hydrogenation is required to produce a suitable synthetic crude. Net product yields are in the range of 80 to 90 percent by volume, based on bitumen consumed.

- As conventional oil becomes more expensive and more difficult to obtain, exploitation of Canadian deposits will become progressively more attractive. The known reserves could theoretically support a very large rate of production. However, for the next 15 years, tar sands output is projected to be limited by economic and technological development considerations to the following range:

	1971	1975	1980	1985
Production (MB/CD)	45	50-75	275-500	500-1,250
Number of Installations	1	1-2	3-4	4-10

- For development to take place, it has been assumed that the total synthetic crude production costs will, within the forecast period, be competitive with the full costs of producing conventional crude of like quality. Capital investment required for either mining or *in situ* production is expected to be about $4,000 per daily barrel of capacity (1970 dollars).

- Government policies, particularly those of Canadian federal and provincial governments, will have a major impact on development and production costs, and hence on the timely availability of tar sands oil as a significant component of United States energy supply.

SUMMARY OF TAR SANDS TASK GROUP REPORT

Tar sands, oil sands and bituminous sands all are terms used to describe 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. Reservoir energy is typically non-existent or minimal, so that for production to be initiated and sustained, some form of energy (heat, fluid pressure, mechanical work by mining machinery, etc.) must be applied. Many such deposits are known, but only a few are likely to become of major commercial interest to North America, and to the United States in particular, in the next 15 to 30 years. Chief among these few are the Athabasca deposit in northern Alberta, Canada, and the Orinoco deposits in eastern Venezuela.

Athabasca bitumen is a naphthene-base, black material and contains relatively large amounts of sulfur, nitrogen and metals. Its specific gravity is in the range of 6° to 10° API. The viscosity of the native bitumen varies widely, but is on the order of 35,000 Saybutt Universal Seconds (SUS) at 100° F, 513 SUS at 210° F. These properties make the material undesirable as a feed to conventional oil refineries, and impossible to ship via pipeline to important refining centers.

Accordingly, some pre-refining or "upgrading" of the bitumen must be practiced in the field to convert it into the synthetic crude of commerce. This upgrading is undertaken to increase the hydrogen/carbon ratio of the bitumen by conserving the native hydrogen and removing some of the carbon (as coke or heavy pitch). The carbon throw-off is then available as fuel for the refining operation and to provide "reservoir energy" for production, as mentioned before.

In the process of hydrogen-enrichment, the sulfur and nitrogen contents are reduced to tolerable levels via hydrogenation and the metals exit with the carbon residue, so the finished synthetic crude is of quite acceptable quality and in some major respects is a superior feedstock for shipment to refining.

This interim summary report will first describe the important known tar sands deposits of the world, with emphasis on North and South American reserves. Next, the nature and present status of production and extraction techniques for mining and/or *in situ* mining of the bitumen will be reviewed, as will the upgrading schemes likely to be used. Very rough, order-of-magnitude estimates of the cost of facilities to produce synthetic crude from tar sands will be given. Finally, an estimate will be made of the synthetic crude production rates which could be attained by 1980 and 1985.

TAR SANDS RESERVES

Tar sands deposits are widely scattered, but those of sufficient size to have a potential importance for U.S. energy supply are restricted to the Western Hemisphere.

1. Canada

Large accumulations of potentially recoverable tar sands do exist in Alberta, Canada. Although much is known about the Alberta deposits, the data are still not totally conclusive as to the extent of the reserves. In the

Athabasca-Wabasca and Bluesky-Gething deposits, 45.1 billion in-place barrels occur beneath an overburden of 100 feet or less. The presence of 80 percent of this quantity has been confirmed by actual drilling according to the Alberta Oil and Gas Conservation Board (OGCB).* Moreover, a high recovery factor can be justifiably attached to this quantity, resulting in the estimated recovery by surface mining and extraction of 27.0 billion barrels of a synthetic crude.

Some 590 billion barrels of bitumen have been estimated by the OGCB to lie beneath overburden cover greater than 250 feet, but only 18 percent of this quantity has been proved by actual drilling. This part of the total accumulation will have to be recovered by *in situ* techniques, for the application of which the reservoir must have certain characteristics not universally present over the entire area. Thus, since only one-fifth to one-sixth of the estimated reserve has been proved by drilling and since, for recovery, reservoir parameters must fall into an acceptable pattern, the task group estimates the bitumen-in-place that would be amenable to *in situ* recovery should be lowered to the more probable value of 300 billion barrels, from which 120 billion barrels of a synthetic crude could be produced.

The amount of bitumen-in-place under an intermediate overburden of 100 to 250 feet has been estimated by OGCB at 75.5 billion barrels of which about 50 percent has been proved by drilling. Part of this will be recovered by mining and part by *in situ* techniques. Again, some discounting for the unproved acreage and for requirements of recovery technology seems appropriate; therefore, the task group estimates the tar-in-place subject to recovery at 54 billion barrels, from which 27 billion barrels of synthetic crude could be produced.

In summary, task group estimates of the extent of the Alberta tar sands reserves are as given below. These are, as noted, lower than the estimates given by the OGCB report, but are still very large reserves.

Overburden	Tar-In-Place Subject to Recovery	Estimated Recoverable	Potential Synthetic Crude*
(Feet)	(Billion Bbl)	(Percent)	(Billion Bbl)
0-100	45	72	27
100-250	54	60	27
250	300	48	120
TOTAL	399		174

* At 1.2 bbl bitumen per bbl of synthetic crude.

Another potentially major source of heavy hydrocarbons in Canada is the Cold Lake area about 125 miles northeast of Edmonton, along the Alberta-Saskatchewan border. The Alberta OGCB has considered these deposits to be oil sands, although the hydrocarbon found there is intermediate in properties between the bitumen of the Athabasca deposits to the northwest and the heavy Lloydminster crudes found in Saskatchewan to the southeast of Cold Lake. The Lower Cretaceous Age deposits are covered with 900 to 1,600 feet of overburden. These deposits cover about 2,900 square miles, and they contain an estimated 75 billion barrels of bitumen. Contiguous lands (Saskatchewan to the east, a federal military reservation to the north) probably overlie extensions of the Cold Lake formations, but no estimates of their potential are available.

*Alberta Oil and Gas Conservation Board, "A Description and Reserve Estimate of the Oil Sands of Alberta" (Calgary, 1963).

Cold Lake hydrocarbon is generally of 10° to 12° API, with 3- to 4-percent sulfur content by weight. Reported viscosities have varied widely from 4,000 to 100,000 Centipoise at 100° F. Some material is lighter than this "norm," ranging to 14.5° API and 250 cp at 100° F.

Conventional production techniques have not been successful in the Cold Lake area. A number of experimental projects using thermal (fire or steam-flood) or other means of stimulation have been carried out, and some further field test work is under way or planned. However, none are now operating to the task group's knowledge.

As with tar sands proper, the existence of a major hydrocarbon deposit at Cold Lake is beyond doubt, but its availability at a competitive price to the U.S. energy market is very uncertain.

2. *Venezuela*

The Venezuelan Orinoco Tar Belt deposit has not been adequately drilled to define its limits and contents in great detail. However, the estimate of the tar-in-place on the order of 600 billion barrels seems to be a most probable value. No significant part of this accumulation is amenable to recovery by mining operations. On the other hand, *in situ* recovery is not limited to the low-recovery thermal soaking operations introduced many years ago in the heavy oil pools of Venezuela and in California. The application of thermal drive techniques would be expected to increase the estimated recovery of tar, but the extent to which this may be accomplished is unknown.

3. *Colombia*

The deposits in the Llanos area of Colombia have not been well defined, but available information suggests the possible presence of almost a trillion barrels of bitumen-in-place.

In summary, the potential production of synthetic crude oil from tar sands in the Western Hemisphere outside the United States could eventually be on the order of 200 billion barrels from the Canadian deposits, and this total could well be increased materially by validation of the reported accumulations in Colombia and by more precise definition of the Venezuelan potential.

4. *United States*

While relatively extensive literature exists as to the occurrences of tar sands deposits in areas other than Canada and Venezuela, little of it is sufficiently detailed to provide the type of data needed for comprehensive resource-reserve analysis. The tar sands resources of the United States and of the world have been reviewed in several relatively recent studies. The Ford, Bacon & Davis estimate of 0.711 billion barrels of strippable reserves, though it was made in 1951-1952, was cited in 1964 as still the latest published figure with a claim to accuracy.* Included in the total were reserves in the tertiary, secondary and primary categories combined. Using the unverified reserve figures available in the literature, as of 1964, Ball Associates

**The Synthetic Liquid Fuel Potential of the United States,* prepared by Ford, Bacon & Davis (a series of volumes published between 1951-1952 and distributed by the U.S. Bureau of Mines, Washington, D.C.).

reported that the recoverable reserves of oil in surface and near-surface petroleum-impregnated rocks in the United States equalled a minimum of 2.495 billion barrels and a maximum of 5.483 billion barrels.*

These reserves were considered "recoverable" because they were reported to be at relatively shallow depths, and were based almost entirely on occurrences in Kentucky, California and Utah, which were the largest and best known of the United States deposits.

For purposes of this review, the most recent significant work on tar sands deposits outside of Canada and Venezuela has been the work by Ritzma and associates of the Utah Geological and Mineralogical Survey.† These investigations have resulted in upward revision of resource estimates for Utah to the point where five "giant" deposits were recognized (deposits with more than 0.5 billion barrels of gross oil-in-place). In total, these contain estimated resources totaling 17.7 to 27.6 billion barrels (see Table XCV).

TABLE XCV

GIANT TAR SANDS DEPOSITS IN THE UNITED STATES

Location (Utah)	Extent (sq.mi.)	Thickness (feet)	Overburden Thickness (feet)	Saturation Percent by Weight	Resources In-Place (Billions of Bbls.)
Tar Sand Triangle	200-230	few-300+	0-2,000+		10.0-18.1
P. R. Spring	215-250	3- 75	0- 250	9?	3.7- 4.0
Sunnyside	20- 25	10-550	0- 600	9	2.0- 3.0
Circle Cliffs	28	few-310	0-1,800		1.0- 1.3
Asphalt Ridge	20- 25	5-135	0- 500	11	1.0- 1.2
					17.7-27.6

Source: P. H. Phizackerley and L. O. Scott, "Major Tar Sand Deposits of the World," *Seventh World Petroleum Congress, Proceedings*, Vol. III, Drilling and Production (Essex, England, Elsevier Publishing Company, Ltd., 1967).

*Ball Associates, Ltd., comp., "Surface and Shallow Oil-Impregnated Rocks and Shallow Oil Fields in the United States," U.S. Bureau of Mines Monograph 12 (Oklahoma City, Okla., Interstate Oil Compact Commission, 1965).

†Howard R. Ritzma, comp., "Preliminary Location Map, Oil-Impregnated Rock Deposits of Utah," Map No. 25, *Utah Geological and Mineralogical Survey* (Salt Lake City, Utah, Utah Geological and Mineralogical Survey, April 1968); "Oil-Impregnated Sandstone Deposits of Utah--A Progress Report," presented December 9, 1969, by Howard R. Ritzma, Utah Geological and Mineralogical Survey to general session of Interstate Oil Compact Commission; U.S., Congress, Senate, Committee on Interior & Insular Affairs, *Tar Sands: Hearings on S.581 and S.582*, 91st Cong., 2nd sess., 13 July 1970, "Statement of Howard Ritzma of the Utah Geological Survey," pp. 40-45.

In addition to these giant deposits, the following smaller Utah deposits were cited by Ritzma in 1970 as being perhaps large enough or so favorably situated as to offer commercial possibilities for extraction of oil:

Area		Smaller Utah Deposits (Millions of Bbl.)
Hill Creek		300-400
Lake Fork		15- 20
Raven Ridge		100-125
Rimrock		30- 35
Whiterocks		65-125
	TOTAL	510-705

Deposits of less than 500 million barrels of oil-in-place (such as those in Utah, the Edna deposit and others in California, and the Kentucky deposits) may become commercial in the future owing to favorable local factors or to changes in technology or economics. It is unlikely, however, that such deposits will significantly affect the total U.S. energy supply between now and 1985, or even to the year 2000. For the purposes of this review, therefore, only the giant deposits (deposits with in-place reserves of 0.5 billion barrels or more) will be considered.

Knowledge concerning giant tar sands deposits outside of Canada and Venezuela is limited. The deposits may be better reported as tar sands "resources" rather than "reserves," inasmuch as there has been no significant production to date from them, and no reliable estimates have been made as to recoverable amounts. Some of these deposits have been quarried locally for rock asphalt over many years or subjected to various research experiments, but no significant amount of oil or gas has been produced. The only known exception to this is the production of gasoline, coke and other products from gilsonite, a solid vein-type hydrocarbon, mined in eastern Utah and transported by a 72-mile slurry pipeline to a refinery in Fruita, Colorado. Even if gilsonite is included with "tar sands," it is not a major consideration in that the original gilsonite reserves in Utah have been estimated at only about 45 million tons.

Although the giant Utah deposits are the most likely to be exploited among all known deposits in the United States, several problems may delay significant production even in this area:

- The Tar Sand Triangle and Circle Cliffs giant deposits are largely on federal lands. Leasing of federal lands for "asphaltic minerals" or tar sands has been delayed pending legislation.
- Proposals for national parks, national monuments, desert wilderness areas and recreation areas cover most of the Circle Cliffs and Tar Sand Triangle giant deposits and could result in surface uses incompatible with mineral resource development.
- Water supply may constitute a serious handicap to exploitation of Utah deposits.
- Tar sands and oil shale are superimposed in the P. R. Spring giant deposit, which may present legal difficulties.
- Most Utah deposits according to Ritzma are not susceptible to mining, but more likely will be developed by *in situ* methods.

In view of these problems, large-scale commercial development of the Utah giant deposits is not likely to occur before 1985. Some of the Utah deposits could be developed, however, in the 1985-2000 interval. Continuing interest in the area is evidenced by the fact that at least 10 companies have maintained land holdings or have conducted experimental work in the region.

5. Other Areas

Other than the Canadian and Venezuelan resources already described, Phizackerley and Scott identified only the 1.75-billion-barrel Bemolanga deposit in Malagasy as having in-place reserves of over one billion barrels.* The Malagasy deposit is not being worked and, in any event, is much smaller and more remote than the prime reserves in the Western Hemisphere.

In 1967, prior to the start of production from the Athabasca tar sands in Canada, only four deposits were being exploited. These are listed below with estimates of their in-place reserves:

	Estimated Reserves In-Place (Millions of Bbl.)
La Brea, Trinidad	60
Selenizza, Albania	371
Derna, Rumania	25
Cheildag, U.S.S.R.	24

None of these deposits have sufficient in-place reserves, based on our present information, to include them in the "giant" class. No production figures were available for the Derna and Cheildag deposits, according to Phizackerley and Scott.† Total production for the La Brea deposit in the period 1961 through 1964 was given as less than 200,000 long tons per year, while export figures for the Selenizza deposit showed less than 28,000 long tons per year during the period 1961-1963. The task group concludes that Eastern Hemisphere sources will be of no importance to future United States energy supplies.

In summary, based on present knowledge, only five giant tar sands deposits in Utah (Table XCV) appear likely to enter into and affect the United States energy supply along with the important Canadian and Venezuelan tar sands deposits. However, the Utah deposits are judged as unlikely to have an important effect in the period to 1985.

EXPLOITATION TECHNIQUES

Conversion of in-place bitumen to a synthetic crude, refinery charge stock is being approached along two paths. One involves mining the tar sands and extracting the bitumen on the surface; the other concept depends on stimulation of the formations so that bitumen will flow underground to wells from which it can be pumped to the surface. Both methods result in a supply of bitumen as feedstock to an upgrading (hydrogen-enrichment) operation more or less akin to conventional refining techniques, wherein the synthetic crude is produced.

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*P. H. Phizackerley and L. O. Scott, "Major Tar Sand Deposits of the World," *Seventh World Petroleum Congress, Proceedings*, Vol. III, Drilling and Production (Essex, England, Elsevier Publishing Company, Ltd., 1967).

†Phizackerley and Scott, p. 571.

1. Mining

The mining-extraction route is most applicable to the shallow deposits (up to 100 or 150 feet of overburden). Because the bitumen content of average sand is normally less than about 12 percent by weight, an immense tonnage of sand and overburden must be moved, using strip mining methods, to support an economically large, synthetic crude output. On a unit basis, the ratio is about 2.4 tons of sand and 1.0 ton of overburden, more or less, per barrel of synthetic crude. Local variations in overburden ratio and/or tar sands quality over a given lease area can result in condemnation, on economic grounds, but always respecting good conservation practices, of significant portions of a lease. Thus, an overall average utilization of total tar sands in a mining leasehold might be on the order of 75 percent.

Many methods have been proposed for recovering oil from mined tar sands. Of these, only the hot water extraction process is in commercial operation so far, being used by Great Canadian Oil Sands, Ltd. (GCOS). The proposed Syncrude Canada, Ltd. (Syncrude), installation will also use a hot-water method. Extraction (recovery) efficiency is on the order of 90 percent, more or less, for this process. A generalized flow diagram is shown in Figure 23.

2. In Situ Recovery

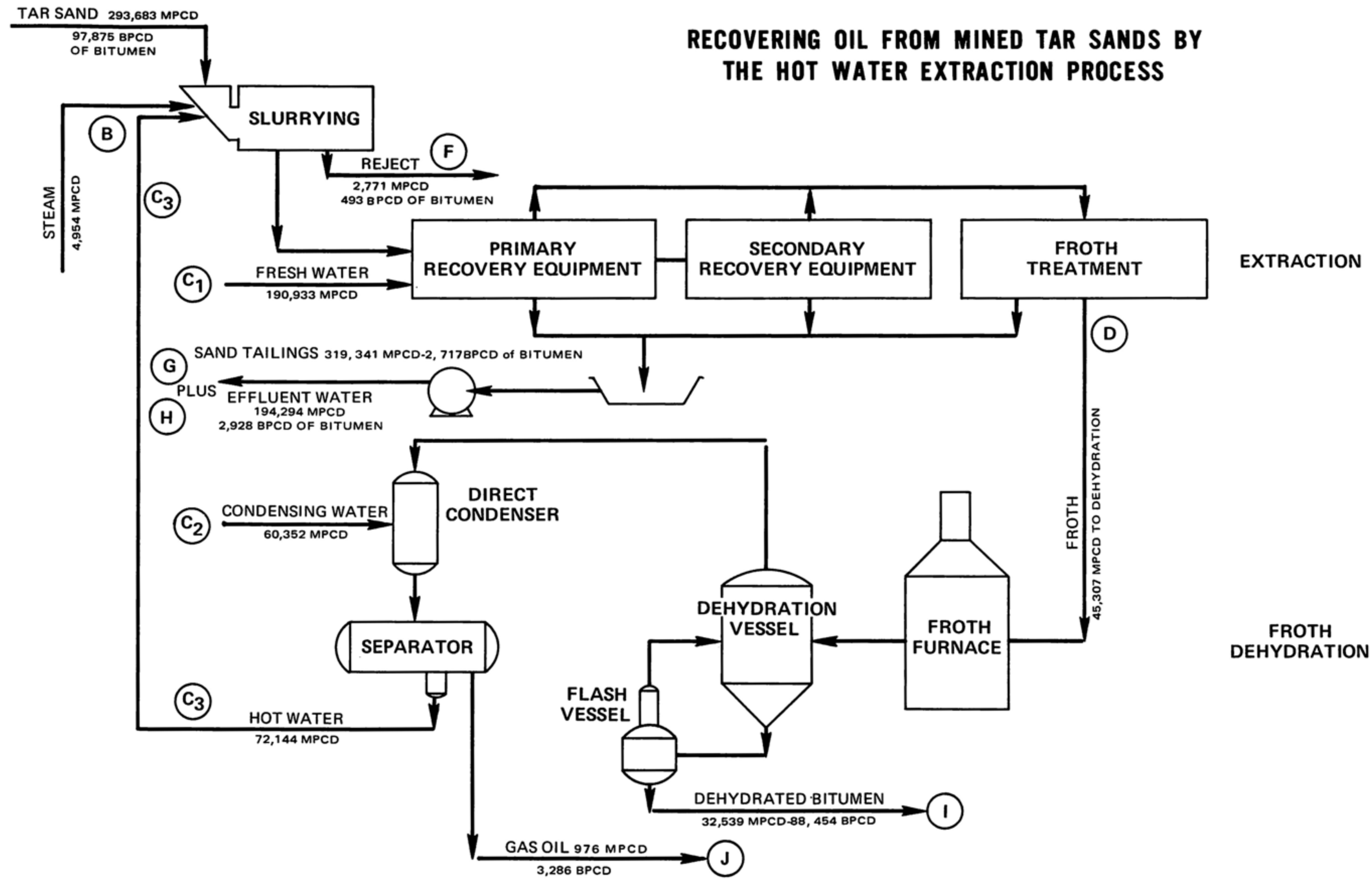
In situ methods of recovery of deep-lying tar sands are not so well developed, and none has been brought to commercial-scale use. The two methods most thoroughly researched and tested in the field involve (1) injecting steam plus an emulsifying agent (e.g., caustic soda, as used in a Shell Oil trial) into the deposit and (2) using thermal-recovery or "fire-flooding" techniques, as experimented with by Amoco (Canada) and others. For either method to succeed, communication must be established down-hole in the formation between the injection wells and the production wells. Field tests have determined that this can be achieved. Overall recovery of in-place bitumen via either *in situ* technique is estimated to be on the order of 35 to 50 percent, distinctly lower than the corresponding value for mining extraction.

3. Upgrading

As stated earlier, upgrading of bitumen to synthetic crude suitable for shipment to refining-marketing centers for manufacture into finished products involves hydrogen-enrichment of the bitumen by some means. Also, for a fuel-balanced operation, necessary in the remote locale of major tar sands deposits, sufficient bitumen or components thereof must be set aside as fuel for the operation, and for production of hydrogen. These requirements result in a synthetic crude product/bitumen volume ratio of from about 0.78 (GCOS, via coking and hydrogenation of coker distillates) to 0.87 (Syncrude, via hydrovisbreaking plus hydrogenation of visbreaker distillates). Presumably *in situ* bitumen would be upgraded in about the same ratio to make a similar synthetic crude. Properties of a typical synthetic crude are given as follows:

API Gravity	32°-34°
Viscosity SUS at 77° F	43
Pour Point °F	+5
Reid Vapor Pressure (Debutanized) PSI	2
ASTM* 50% Point °F	500
ASTM* End Point °F	1,000
Percentage of Sulfur by Weight	0.3
Percentage of Nitrogen by Weight	0.07

* ASTM = American Society for Testing Materials.



MPCD - THOUSAND POUNDS PER CALENDAR DAY (TOTAL MATERIAL)
BPCD - BARRELS PER CALENDAR DAY (100% BITUMEN)

Source: Syncrude Canada Ltd., 1968

Figure 23. Extraction-Dehydration System (Syncrude-1968) (Schematic Flow Diagram).

POTENTIAL PRODUCTION FROM TAR SANDS

To sum up, tar sands reserves of potential interest as a major source of energy for the United States exist certainly in Alberta and probably in Venezuela and Colombia. Techniques for exploiting these reserves are under development, and in one company, GCOS, commercial production has begun.

What are the prospects for increased production over the next 15 years? We will focus on the Athabasca-Cold Lake areas, since these are closest to the United States; are in a contiguous, friendly, stable country; and have been the most thoroughly studied.

The rate of initiation and expansion of tar sands production will be governed in the long run by economics. Tar sands oil is now more expensive than conventional production, but as (and if) the latter becomes scarcer in North America and less reliable and/or more costly from overseas sources, a point could be reached where exploitation of tar sands will become competitive. At that time--which the task group believes will likely be after 1980--and assuming that technological progress has continued in the 1970's, especially in regard to *in situ* methods, tar sands oil output could be expanded as rapidly as capital could be made available. For the next 10 years, however, the task group sees economic and technological factors and, possibly, construction industry saturation as limiting tar sands oil output to those projects currently under way or announced, plus some currently less well-defined projects in the talking stages. Post-1980, if economics are right, yearly expansion at an average rate of perhaps 100 MB/D might be supported, leading to about 1 MMB/D capability in 1985. The range of values is shown to indicate somewhat the degree of uncertainty judged to be inherent in these estimates at present.

TABLE XCVI

ESTIMATED PRODUCTION OF TAR SANDS OIL
(MB/D)

Installation	1971	1975	1980	1985	
Initiation: Pre-1980					
GCOS (M)*	45	50	50	50	Capacity of Original Installations Plus Nominal Expansion Over Time.
Syncrude (M)	--	--	125	150	
Shell (M or I†)	--	--	100	150	
Others (M or I)	--	15	100	150	
Initiation: Post-1980	--	--	--	500	
TOTAL	45	65	375	1,000	
Likely Range		50-75	275-500	500-1,250	
Number of Installations	1	1-2	3-4	4-10	

* M=Mining.

† I=*In Situ*.

Lead times are an important consideration in estimating near-term production possibilities. Mining ventures will require 4 to 7 years from inception to reach full production. The first major *in situ* ventures, requiring more process development testing, will require 5 to 10 years. Field construction labor supply and vendors' shop capacity are also possible limits to very rapid expansion of output. Community facilities need to be built, also, to house and serve workers and their families. It seems unlikely that development could be possible at a rate much faster than that shown through 1980.

CAPITAL INVESTMENT AND OPERATING COSTS

The task group's judgment is that facilities to produce synthetic crude from Athabasca tar sands via either the *in situ* or the mining method will cost on the order of $4,000 per daily barrel (1970 dollars), for a nominal 100 MB/CD installation. This amount will pay for:

- Production machinery and equipment
- General plant facilities (site preparation, roads, dikes, buildings, shops, offices, etc.) "inside-the-fence"
- Utilities generation and distribution equipment
- Working capital (spare parts, inventories of oils and other stocks, ready cash, etc.)
- Land, lease rights, etc. (generally these are small costs relative to the total).

Not included are pipelines or other transportation facilities, access roads and other public works, community facilities and housing for personnel, and the cost of the extensive process development and engineering studies necessary for "first ventures" but not for subsequent similar installations.

Operating costs are more difficult to generalize. Ranges of capital-related costs can be estimated from the $4,000 per B/D investment value, but other operating costs would vary widely, since they are directly related to the type of process employed. Mining ventures, for example, must pay for excavating, transporting and depositing some 3.5 tons of earth per barrel of oil, which cost will be avoided by *in situ* ventures. These, in their turn, have costs of on-going well drilling and equipping operations to sustain production.

In addition, Canadian government policies with respect to such items as pollution abatement, taxes and royalties will affect the costs of operations in Canada and, consequently, the capability for growth. For example, a royalty must be paid to Alberta in the case of the Athabasca-Cold Lake material; but the pattern for the basis and amount of this charge is not yet fixed.

The task group's projections of the output of syncrude from tar sands assumes that the total costs, including return on investment from synthetic crude, will, within the forecast period, be in a range which is competitive with crude oil of like quality at the upgrading plant.

In addition to those references cited in footnotes, the following references are cited for this report:

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Chapter Thirteen

Hydropower and New Energy Forms Task Group

Summary of Report

NEW ENERGY FORMS TASK GROUP

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NEW ENERGY FORMS TASK GROUP REPORT

ABSTRACT

Hydropower and any new forms or sources of energy that might be developed are of interest and significance in the light of rising energy needs and the problem of meeting them with fossil fuels and nuclear power. This is true no matter how small their current or immediate contribution.

As of January 1, 1971, hydropower supplied about 16 percent (249 billion KWH) of the energy requirements for electric power generation. Conventional hydroelectric energy had been so extensively developed in the United States, however, that few desirable unused sites remained. Thus, although growth of conventional hydroelectric generation is expected to continue in the period 1971-1985, that growth is projected to average only about 1.6 percent per year. Even so, it would have to include small sites, generally of less than 200 megawatt (MW) capacity. As a consequence, it is estimated that only about 7 percent (316 billion KWH) of total electric power will be supplied by hydroelectric generation in 1985. Although pumped storage hydropower capacity is expected to increase rapidly during this period, such hydropower does not represent primary energy.

Several potential new energy forms have been examined for the initial appraisal. These include geothermal energy, energy from agriculture, solar energy, tidal energy and such energy conversion devices or systems as fuel cells, thermionic devices, total energy systems and magnetohydrodynamics (MHD). Several of these may become increasingly important beyond 1985, depending generally on progress made in technical development before that time. For some of the new energy forms to attain their full potential, extensive research is necessary, and the magnitude of this research effort in the period 1971-1985 will directly affect the speed with which their potential can be realized. Prior to 1985, however, the amounts of primary energy they are likely to provide and the impact they are likely to have on the use of fossil and nuclear fuels are expected to be relatively small in the overall domestic energy picture.

In the western portion of the United States, the development of geothermal energy appears promising for the 1971-1985 period. A capacity of 82 MW has been available since 1970. Projections of planned development in California and in Nevada lead to an estimate that 7,000 MW of installed capacity may be achieved by 1985 in PAD District V. If desalinization proves feasible in the Salton Sea area and if heat exchangers are developed so that lower-temperature hot-water systems can be produced economically, installed capacity could be as high as 19,000 MW by 1985. However, this would still represent only 2 percent of the total U.S. electric generating capacity at that time.

SUMMARY OF NEW ENERGY FORMS TASK GROUP REPORTS

HYDROELECTRIC ENERGY

Most of the usable sites for significant development of hydroelectric energy in the United States have already been utilized. Some growth will occur from 1971 through 1985 but will probably average only about 1.6 percent annually. Thus, hydroelectric energy will not maintain its share of electric power generation in this period.

Except for a few large new sites ranging from 500 to 2,500 MW, the planned developments for 1971-1985 will include mostly small sites of less than 200-MW capacity. If the planned additions occur during the 15-year period, 316 billion KWH will be generated by hydroelectric means in 1985, compared with 249 billion in 1970. It is estimated that hydroelectric power will then contribute about 7 percent of the electric energy, compared with 16 percent in 1971.

Most of the expansion of hydroelectric power will occur in the western areas of the United States--about 84 percent of it in PAD Districts IV and V (see Tables XCVII and XCVIII). An increase of only 10 billion KWH can be expected to be contributed by hydroelectric PAD Districts I, II and III. This amount of energy is approximately equivalent to 2,000-MW capacity of either fossil or nuclear plants. Thus, the available hydroelectric energy will barely affect requirements for coal, oil, gas and nuclear power east of the Mississippi.

An important trend has been occurring in recent years toward the design of hydroelectric plants for peak load operation. Increased this way, capacity can be built into existing sites and energy can be supplied in larger blocks--albeit over a shorter period of time. Of course, the total amount of energy does not significantly change. As evidence of this trend, a good many future hydroelectric plants will operate at an annual average capacity of 20 to 25 percent, and average operating factors for newly installed capacity in the 1971-1985 period will be about 33 percent. This contrasts with the average operating factor of about 55 percent for the United States in 1970. There is also a trend toward rating the capacity of new, undeveloped sites at a higher level than was formerly the custom. Undeveloped capacity, therefore, does not relate directly to undeveloped or available energy.

If planned expansions occur, about 60 percent of the potential hydroelectric energy in the United States will be harnessed by 1985. Necessarily, the undeveloped potential will be mostly widely scattered small sites in the 50- to 150-MW range that may never be developed for economic reasons. Other factors may limit the development of some new sites. Some laws have been passed and more proposals made at the federal level to preserve rivers in their natural wild state. In addition, the states are removing sites from the inventory of the total potential by additional legislative action.

A developing trend in the United States is the use of pumped-storage hydroelectric power. Pumped storage is not a *primary* energy source and should not be counted as such. However, about 40 billion KWH is expected to be generated with pumped storage in 1985. Pumped storage is most complementary to nuclear energy and is expected to be mostly confined to nuclear plants. If pumped storage is used with coal-fired plants, the thermal efficiency of the overall generating complex is lowered by a slight amount.

TABLE XCVII

CONVENTIONAL HYDROELECTRIC POWER GENERATION
BY PAD DISTRICT
(Billions of KWH)

	PAD Districts					
Year	I	II	III	IV	V	Total
1970	44.2	30.1	10.8	19.0	144.9	249
1975	46.0	30.1	12.5	25.0	157.4	271
1980	48.5	29.3	15.0	31.3	171.9	296
1985	50.0	30.0	15.5	38.0	182.5	316

TABLE XCVIII

ENERGY FROM HYDROELECTRIC SOURCES BY PAD DISTRICT
(Trillion BTU's)

Year	PAD Districts I	II	III	IV	V	Total
1970	475	324	116	204	1,558	2,677
1975	482	315	131	262	1,650	2,840
1980	497	300	154	321	1,761	3,033
1985	494	296	153	375	1,800	3,118

Were it assumed, however, that mine-mouth coal plants would be used for 25 percent of the pumped storage in 1985, only an additional 2 million tons of coal would be required for that year, hardly a significant amount.

GEOTHERMAL ENERGY

The development of geothermal energy in Western United States appears promising for the 1971-1985 period. Commercial development of the Geysers Field, California, began in 1960 and a capacity of 82 MW existed in 1970. Planned expansion by one operator is expected to increase to about 600 MW by 1975. In estimating the amount of geothermal power expected to be developed through 1985, it was assumed that the recently passed federal law permitting leasing of federal lands will stimulate exploration in areas of favorable geological indications of steam. Projections were made on the planned development of the Geysers Field as well as presently sub-commercial fields in California and Nevada. Accordingly, it is estimated that 7,000 MW will exist by 1985 (Table XCIX), an increase by a factor of nearly 100 in 15 years.

All of this will be in California and Nevada and available in PAD District V. Total generating capacity in California and Nevada should grow to 75,000 to 90,000 MW by 1985. Accordingly, in those two states geothermal steam should account for about 9 percent of the total generating capacity in 1985. Since geothermal steam will have a high load factor, it should contribute about 11 percent of the generated electrical energy.

The cost of developing geothermal production is estimated to be 0.525¢ per KWH at the present time (see Table C, p. 186). Information for arriving at this figure was taken from experience at the Geysers Field, California. A load factor of 85 percent was used, representing a compromise between 1970 production figures and the load factors predicted for the future. Costs can be broken down to 2.66 mills for steam costs delivered to the plant, 0.45 mills for operating costs and 2.14 mills for capital costs. It was assumed that the cost of geothermal power will be cheaper than that derived from fossil-fuel steam plants and that it will be developed faster than nuclear steam plants at roughly the same costs per KWH.

For every vapor-dominated geothermal system discovered, it has been estimated there will be 20 hot-water systems found. Since no hot-water system fields are yet in production in the United States, we have no cost data for comparison to the Geysers. Experiments with dual-fluids heat-exchanging techniques now being conducted near Reno, Nevada, give promise that lower temperature hot-water systems can be produced economically.

If heat exchangers are developed, additional prospects will be attractive for exploration. The availability of suitable heat-exchange techniques is reflected in the estimates of additional capacity. For example, the installed

TABLE XCIX

ESTIMATED GEOTHERMAL STEAM GENERATING CAPACITY FOR PAD DISTRICT V (MW)

Cost (¢/KWH)	1970	1975	1980	1985
0.525	82	1,500	4,500	7,000
0.575	--	--	4,000	7,000
0.625	--	--	2,000	5,000
TOTAL	82	1,500	10,500	19,000

TABLE C

EQUIVALENT ENERGY FROM GEOTHERMAL SOURCES* (BTU x 10^{15})

Cost (¢/KWH)	1970	1975	1980	1985
0.525	0.0066	0.117	0.343	0.514
0.575	--	--	0.305	0.514
0.625	--	--	0.153	0.367
TOTAL	0.0066	0.117	0.801	1.395

* Based on an 85-percent operating factor.

capacity could be estimated to be as high as 19,000 MW by 1985 (Table XCIX), based on such development. The increase in power cost from 5.25 mills to 6.25 mills (Table C) for more complex equipment is speculative, however.

Most of the exploratory drilling conducted to date has been in areas of high heat gradient and near-boiling hot springs. Only a small number of such areas have been tested so far, however, although all the states of the United States lying west of the Continental Divide (encompassing California, Oregon, Washington, Idaho, Nevada, Arizona, New Mexico and parts of Montana, Wyoming and Colorado) are potentially good hunting grounds. Good surface indications of volcanic activity, high heat gradient and numerous hot springs, such as are found throughout the western part of the United States, suggest that there are many prospective sites that may eventually be capable of steam and/or hot water production. The recently enacted Federal Geothermal Leasing Act would make available millions of acres of promising land for prospecting. There has been a corresponding increased interest in obtaining leases and in conducting explorations.

In estimating the amount of geothermal energy available in 1980 and 1985, the task group has assumed that only a small portion of the potential prospects will prove to be commercially productive. Scarcity of population and lack of a market in protions of the western states will discourage exploration in areas that otherwise would be good prospects.

Present indications are that exploration will be conducted for the most part by private industry, including public utilities and oil exploration companies, as well as companies specifically organized for the exploration and development of geothermal power. The Federal Government's Bureau of Reclamation has been active in financing R&D for the Imperial Valley. If desalinization proves feasible in the Salton Sea area, power development may proceed faster than has been indicated from 1980 to 1985.

For appraising the longer range prospect of geothermal energy, not only localized hydrothermal systems should be considered, but also the deep sedimentary basins that contain large masses of water. The prospective amount of heat in such waters of U.S. sedimentary basins is considerable, and the total amount of energy that may be recovered from such sources may well surpass the heat to be derived from combustion of the oil and gas in those basins.

Several uncertainties exist, however, with respect to current estimates about the possible size of the resources. The magnitude of the *in situ* heat reserve depends mainly on such factors as the temperature at depth, the porosity of the sedimentary section, the section thickness and the lateral extent of the permeable sediments. How much of this heat can be recovered hinges on such factors as permeability, lateral continuity, size of hydraulically connected water masses, sub-surface water pressure and the effectiveness of flashing as a means to lift the thermal waters. Knowledge of the above-mentioned factors is limited for the deep parts of the sedimentary basins. Exploration efforts in these areas will be a function of the above-mentioned uncertainties, the large resource potential and the prospective economics.

It seems possible that the uncertainties could be resolved, at least for some sedimentary basins, before 1985. If resolved favorably, then geothermal energy could attain, in the United States, a greater role in supplying electric energy and heat than is indicated in this report.

ENERGY FROM AGRICULTURE

The efficiency of U.S. agriculture has advanced so fast that for several decades crop production, except in times of international conflicts, has exceeded demand. Average farm production has increased about 80 percent in the last three decades, largely owing to better yielding seeds and greatly improved "know-how." Thus, to meet our crops needs, we plant fewer acres and require fewer farmers.

Agriculture provides the major current source of renewable energy. Forests, cultivated crops and pasture land may be used repeatedly under proper management. Agriculture production is, however, subject to weather, diseases and other natural conditions which cannot yet be completely controlled. Nevertheless, average production in excess of priority requirements for domestic food, feed and fibers is believed possible to 1985 and beyond, barring natural disasters or national emergencies. The production of cereal grains and their conversion through fermentation to usable ethyl alcohol fuel; the collection and use of such residues as straws, corncobs, hulls and shells for fuels; the growing of crops for fuel energy; and the conversion of animal by-products into fuels are all possibilities.

Agricultural fuels would normally be more expensive than such traditional fuels as coal, gas, oil and waterpower. Increasing U.S. needs for energy, requirements for pollution abatement and many other economic factors could, however, materially change the future role of agriculture as a source of industrial energy.

Of the approximately 2,260 million acres of U.S. land available, about 25 percent is classified as forest and woodland and about the same proportion as land suitable for cultivation. Most of our woodland will probably be required to meet the predicted demands for the lumber, pulp and paper industries, and thus will offer only minor possibilities for contributing to additional U.S. industrial energy supplies. On an average, however, only about 60 percent of the potentially available cultivated land is now farmed for crops. Yields of cereal grains on these lands have, on an average, increased about 3 percent annually for the past decade. This increase has exceeded the U.S. population growth, even though the amount of cultivated land has decreased. Thus, unused acres constitute a potential source of energy for the foreseeable future.

A logical sequence of energy conversions is to use this land to produce cereal grains, which are largely carbohydrate, and then to convert these grains by fermentation into ethyl alcohol, which is a convenient combustible fuel readily usable in motors. If we assume that the 100 million acres, or about one-half of the acres not now required, are used to produce the grain for alcohol at a yield of 70 bushels per acre, this would be equivalent to about 18 billion gallons of alcohol, or over 20 percent by volume of the 86 billion gallons of motor fuel consumed in the United States in 1970. Since ethyl alcohol contains only 65 percent of the energy content of gasoline, on a gallon basis, the actual energy replacement would be only 14 percent.

The cost of this ethyl alcohol from fermentation would be many times higher than the cost of present motor fuel. Even so, this tremendous energy potential must be considered in any assessment of future energy sources. Additional advantages may accrue from energy produced within the United States owing to the favorable impact on balance of payments.

The quantity of collectible agricultural residues in the United States amounts to over 130 million tons annually. The heat equivalent of this amount would be on the order of 2,000 trillion BTU's. These agricultural residues with all their potential energy could not now compete economically with such traditional fuels as coal or oil. The growing of crops specifically as an energy source is also a possibility. The production of synthesis gas (carbon monoxide and hydrogen) from agricultural residues or from crops grown specifically for energy is also a possibility. Synthetic liquids or pipeline gas can be made from synthesis gas with partly known technology. Additional research and development work would be required for the gasification of agricultural material.

Although the total potential energy from agricultural residues is large, it is doubtful that, because of economics, these sources can have a significant effect on the U.S. energy picture by 1985.

SOLAR ENERGY

Agriculture represents a special case of indirect solar energy conversion. Other possibilities exist for the direct and indirect use of solar energy. However, as long as fossil fuels remain abundant worldwide, even at substantially higher prices, the utilization of solar energy will be confined to small experimental installations and unique situations.

Because it is so diffuse and intermittent when it reaches the earth, solar energy can be put to no foreseeable large-scale use over the next 15 years, even with appreciable improvements in technology.

The large area over which solar energy must be collected and the cost of the collection and conversion equipment prevent the widespread use of such devices as solar evaporators, solar desalinators, solar heaters, solar cookers, solar furnaces, solar cells, solar houses, etc. Another factor which discourages the use of solar energy is that fossil fuels are available to do the same job night and day without cloud interference.

The silicon cell, developed about 15 years ago, has proved to be a reliable means for direct conversion of solar radiation to electricity for applications in outer space. The generation of significant amounts of power, however, requires the connection of extremely large numbers of cells. The high capital cost of silicon cell arrays results in power costs on the order of $2.00 to $5.00 per KWH. Thus, the cost is about 1,000 times that of conventional power sources.

Based on current research levels on solar energy cells, no breakthrough is anticipated before 1985. The time when this ultimate source of energy will have to be used to supplement the dwindling supplies of other sources remains indefinite but could be as soon as the year 2000. When this time comes, solar energy will have to be used not only to produce power and heat but also, with the aid of chemistry and other resources, to produce the fuels and lubricants for mobile equipment, as well as rubber, plastics and other essential petrochemicals. Such conversion can be achieved with the aid of the hydrogenation of carbon monoxide, but attainment of this goal will require several years of sophisticated research and development.

A greater recognition by government of the ultimate need for solar energy could occur in the next 15 years. If the use of solar energy utilization is ever to achieve any prominence in the United States, it would appear that its development must be supported by government just as atomic energy was.

TIDAL ENERGY

The major problem with tidal energy is that only a small potential exists for the United States. A second major problem is the high capital costs of development.

A tidal range (distance between high and low water) of about 18 feet exists at Passamaquoddy Bay on the coast of Maine. Otherwise, the tidal range of 2 to 6 feet on the U.S. coast is too low even to be considered.

Extensive engineering and advanced planning of a tidal energy plant on Passamaquoddy have occurred over the years. The total energy from the Passamaquoddy Bay area would correspond to about 2 billion KWH per year. As the energy demands of the Northeast have grown, the significance of this amount of energy has lessened. Estimates of capital costs have ranged as high as $1 billion.

A larger potential of tidal energy exists at the Canadian Bay of Fundy. This area has also been extensively studied for a number of years. Three sites on the Bay of Fundy have been estimated to have a potential of about 13 billion KWH per year. In 1969 the Canadian government concluded, however, that development was not economical. Postponement of additional engineering studies was recommended until such time as interest rates and the availability of alternate energy sources declined.

Some possibility exists that the Canadian government will develop a portion of the Bay of Fundy before 1985. Some of this power could become available to the New England region of the United States. On the assumption that a maximum of 10 billion KWH of tidal power will be available by 1985, this could account for about 7 percent of the electrical energy required by the New England region. While the renewable nature of tidal energy is a definite advantage, the total amount of energy is relatively low.

ENERGY CONVERSION DEVICES

1. *Fuel Cells*

Much government and private funding supported fuel cell R&D from the middle 1950's through the middle 1960's. Then both government and private interest waned rapidly in the late 1960's, owing to persistent technical problems. Only one fuel cell operating on a practical commercial fuel has yet advanced beyond the laboratory state. Low-temperature cells using noble metal catalysts and pure hydrogen and oxygen fuels were developed, however, and produced for space use.

Intermediate-temperature molten salt electrolyte cells and high-temperature solid electrolyte cells are no longer under major development programs. Two major U.S. programs remain active, both in laboratory stages, using low temperatures and noble metal catalysts and seeking other catalysts. One uses methanol as fuel and is aimed first at off-the-road vehicles. Because it could capture only a fraction of this market, which in any case now accounts for less than 1 percent of all vehicular fuel use, the impact would be insignificant even if this program should be successful before 1985. The other program, using natural gas, aims shortly to install some sixty 12.5-KW prototype reformer-fuel cell packages on test in various services. However, this approach appears to face future problems of gas scarcity and competitive costs. Moreover, its overall efficiencies are only 35 to 45 percent (because of losses in reforming the fuel) and thus are little better than those of competitive energy supplies. As a result, this second program is not expected to affect fuel demand significantly, even if successful.

Capital costs of both of these types of fuel cells will be no less than those of conventional generating plants. Intermediate- and high-temperature fuel cells have neither efficiency nor investment advantages over prospective magnetohydrodynamic-topped or thermionic-topped fossil-fueled or nuclear generating stations.

Barring a breakthrough in direct use of hydrocarbons without reforming or in cost of pure fuels such as hydrogen, methanol or hydrazine, fuel cells are not likely to have any significant effect on the U.S. fuel economy.

2. *Thermionic Devices*

Thermionic conversion of heat to electricity is in the early stages of development, no practical device having emerged from the laboratory and only conceptual integration into practical systems having been performed. Development is faced with difficult materials problems, related to operating temperatures above 3,000° F and, in isotope-fueled devices, to radiation damage.

Efficiencies of thermionic diodes are theoretically limited to 35 to 40 percent, but the best realized efficiencies are below 20 percent, at operating temperatures near 3,000° F. Laboratory system efficiencies do not now exceed 10 percent. This limits the prospective large-scale use of thermionic power generation to topping of conventional fossil-fueled or nuclear generating stations. Although probable capital costs per KW for the thermionic systems in such use are higher than those of conventional stations, increased fuel efficiency could make them economically attractive.

Only very limited government or private funding is now being applied to thermionic development, and it is not expected that large-scale commercial use will be possible--even assuming that materials problems will be conquered--before 1985.

3. *Total Energy Systems*

Total energy systems are defined as prime movers driving electrical generators with heat recovery to meet all energy needs in residential, commercial, institutional and small industrial establishments. Their economic appeal rests on high system fuel efficiency (up to about 70 percent) and low energy costs of selected fuels versus network electricity. Natural gas and diesel engines and natural gas turbines are the usual prime movers. The number of total energy installations in the United States enjoyed a rapid growth rate, from near zero in 1960 to several hundred in the late

1960's, promoted chiefly by natural gas utility companies. The growth rate in the late 1970's may be augmented by the ready availability of compact gas turbines, built for use in heavy trucks, in sizes up to about 500 horsepower.

A probable U.S. limit of about 14,000 total energy plants is projected, averaging about 2,000 KW electrical capacity in place in 1985. The effects would be a reduction of 170 trillion BTU's per year or less in fuel use by electrical utilities, and an increase of 58 trillion BTU's per year or less in use of natural gas and diesel fuel in the residential, commercial, institutional and industrial sectors.

Because of the increasingly less favorable economics expected beyond 1975 for natural gas and the marginal rate of return on investment of many current installations, it is not expected that the proportion of total energy installations to total U.S. building construction will increase after 1975.

4. *Magnetohydrodynamics (MHD)*

The potential impact of MHD on our energy requirements is a function of its promise of achieving higher thermal efficiency, with the result that less primary energy would be required for electric power generation. In addition, the higher electrical conductivity of combustion products from coal has offered the promise of a simple conversion device which is ideal for our most abundant fossil fuel.

Much R&D work on MHD was sponsored by private industry and government in the period 1955-1965. The work then tapered off after 1965 to the point where only one relatively modest U.S. effort on practical power generation remained in operation in 1971.

Many major technical and engineering problems remain before MHD can emerge as a practical and reliable power device. Major problems include combustion and gasification, the development of high-temperature preheaters, recovery of seed, development of long-life MHD channels and electrodes, corrosion prevention and means to cope with high nitric oxide levels.

Combustion products from fuels such as petroleum distillates and natural gas give low electrical conductivity in MHD ducts. The thermal efficiency of MHD-topped plants with petroleum fuels is significantly lower than with coal or coal-gas as a fuel. While efficiency can be improved by increased temperature and larger magnet size, even greater problems can be created. Improvements in the combined Brayton-Rankine cycle, which are likely to occur before 1985, offer serious competition for MHD. For this reason the electrical equipment, utility and equipment industries today show only limited interest in MHD conversion.

It appears that the MHD concept can first emerge as a peaking or emergency power plant with distillate or residual fuels. With adequate funding, a large prototype peaking plant might be available by 1978.

For MHD to be applicable to base load plants fired by coal, a long-term and costly program extending beyond 1982 seems likely. Even if sufficient funding occurs, some probability exists that engineering problems will not be solved in a way that will be practically or economically acceptable. While competitive and lower capital costs have been projected for MHD-topped steam plants, reliable economics must await the demonstration of MHD on a large-scale for long duration. Base load MHD-topped plants fired by coal are far from successful development. Since peaking plants have only a small effect on our total energy requirements, no significant effect from MHD seems likely before 1985.

List of Abbreviations

ABBREVIATIONS USED IN THIS REPORT

ABBREVIATION	DEFINITION
AAI	average annual increase (percent)
AAPG	American Association of Petroleum Geologists
AEC	Atomic Energy Commission (also USAEC)
AGA	American Gas Association
AGR	advanced gas-cooled reactor
API	American Petroleum Institute
ASTM	American Society for Testing Materials
B	barrel(s)
bbl	barrel(s)
B/CD*	barrel(s) per calendar day
BCF	billion cubic feet
B/D*	barrel(s) per day
BP	British Petroleum Company
BTU (BTU's)	British thermal unit(s)

Petroleum Products Conversion Factors
(Bureau of Mines)

Natural gasoline	BTU/barrel	4,620,000
Liquefied gases	"	4,011,000
Jet fuel, naphtha-type	"	5,355,000
Jet fuel, kerosine-type	"	5,670,000
Gasoline (including aviation)	"	5,248,000
Special naphtha	"	5,248,000
Kerosine	"	5,670,000
Distillate (including diesel)	"	5,825,000
Residual fuel oil	"	6,287,000
Still gas	"	6,000,000
Lubricants	"	6,065,000
Waxes	"	5,537,000
Petroleum coke	"	6,024,000
Asphalt and road oil	"	6,636,000

CF	cubic feet
cp	centipoise
DEI	Development Engineering, Inc.
DWT	deadweight ton
ENEA	European Nuclear Energy Agency

*No distinction is made between per day and per calendar day.

EP	end point
FPC	Federal Power Commission
FRC	Future Requirements Committee/Council
GCOS	Great Canadian Oil Sands, Ltd.
GDP	gaseous diffusion plants
HRI	Hydrocarbon Research, Inc.
IAEA	International Atomic Energy Agency
IPAA	Independent Petroleum Association of America
KW	kilowatt
KWH	kilowatt hour(s)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LWR	light water reactor
MB/CD*	thousand barrels per calendar day
MB/D*	thousand barrels per day
MMB/D	million barrels per day
MCF	thousand cubic feet
M^2CF/D	million cubic feet per day
MHD	magnetohydrodynamic
MPCD	thousand pounds per day
MT SWU	metric ton(s) separative work unit
MW	megawatt(s)
MWe	MW/electricity
NGL	natural gas liquids
NICB	National Industrial Conference Board
NPC	National Petroleum Council
OGCB	Oil and Gas Conservation Board
OIP	oil-in-place
OOIP	original oil-in-place
OPEC	Organization of Petroleum Exporting Countries
PAD	Petroleum Administration for Defense

*No distinction is made between per day and per calendar day.

PSIA	pounds per square inch absolute
Pu	plutonium
R&D	research and development
R/P	reserve to production ratio
RVP	Reid vapor pressure
S	Sulfur
SUS	Saybolt Universal Seconds
TCF	trillion cubic feet
TOSCO	The Oil Shale Corporation
U_{235}	isotope of uranium used as nuclear fuel
U_3O_8	uranium oxide
UF_6	chemical state of uranium for enrichment in U_{235}
USBM	U.S. Bureau of Mines
VLCC	vary large crude carrier