EGN 64

ENVIRONMENTAL GEOLOGY NOTES

JULY 1973 ● NUMBER 64

THE U.S. ENERGY DILEMMA:

THE GAP BETWEEN TODAY'S REQUIREMENTS AND TOMORROW'S POTENTIAL

Hubert E. Risser

ILLINOIS STATE GEOLOGICAL SURVEY

John C. Frye, Chief ● Urbana, IL 61801

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Hubert E. Risser

INTRODUCTION

In the winter of 1972-1973, many individuals, government organizations, and business and industrial concerns in the United States were, for the first time, directly affected by the current energy dilemma. A prolonged cold period over a widespread geographic area led to an especially heavy demand for heating fuels. Delivery of natural gas to electric utilities and industrial firms, especially those purchasing gas on an interruptible basis, was temporarily cut off to assure adequate supplies for households and other high priority users. As inventories of fuels dwindled, fuel oil suppliers and distributors found it necessary to allocate carefully and, in some cases, to ration the quantities provided to consumers.

Although inconvenience and some economic loss were suffered, the overall effects were not severe, for with the arrival of warmer weather the situation was soon relieved. While the problem was primarily regional rather than national in scope, it did demonstrate to a limited degree the types of problems that can be anticipated nationwide from the greater scarcity of fuels that is developing. It was an early but mild manifestation of a predicament that is almost certain to persist throughout this decade and well into the 1980s.

By the end of 1972, domestic output of both oil and natural gas had essentially reached the utmost productive capacity of the existing known reserves. No further expansion of output is possible until the rate of discovery and development of new reserves is increased or until substantial improvements can be made in the percentage of ultimate recovery from identified deposits. Some unutilized coal-mining capacity remains, but most of the mines with unused capacity are located in coal fields with a sulfur content too high to meet current or proposed sulfur emission standards for stationary fuel-burning facilities.

Progress is being made in finding ways to produce liquid fuel and gas of pipeline quality from coal, recover oil from oil shale, and develop advanced nuclear reactors on a commercial basis. Progress also has been made in efforts to utilize energy from unconventional sources, among them geothermal, solar, and tidal sources. Some of these efforts will probably result in no more than limited contributions to our future energy supplies; others are likely to become major sources of supply. Ultimately, a combination of some of these various potential sources can be expected to provide the needed large additions to our energy supply, but none of them is now in a sufficiently advanced stage of development to offer significant relief for at least the next few years.

Before the existing potential for energy can be realized, numerous economic, technologic, environmental, and resource problems that are currently impeding any immediate solution of the nation's energy dilemma must be overcome. This report identifies some of the factors contributing to the dilemma and discusses various aspects of proposals that have been offered as solutions to the problem.

CURRENT ENERGY SITUATION

Trends in Energy Consumption

Total consumption of energy in the United States in 1972 was estimated at 72,091 trillion Btu (U. S. Bur. Mines, 1973a, p. 1). The sources of this energy and their percentage contributions are shown in figure 1.

The fossil fuels—oil, gas, and coal—provided 95 percent of the total energy consumed during 1972. The remainder was provided by hydroelectric, nuclear, and geothermal sources. An estimated 19.7 percent of the crude petroleum and

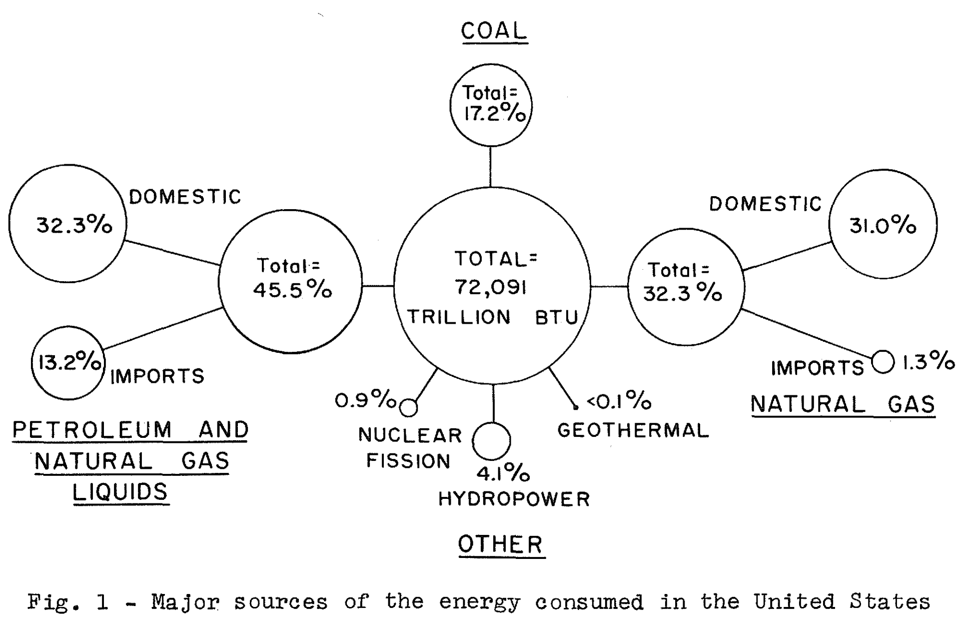


Fig. 1 - Major sources of the energy consumed in the United States in 1972. Size of circle is proportional to the quantity of energy supplied by each source.

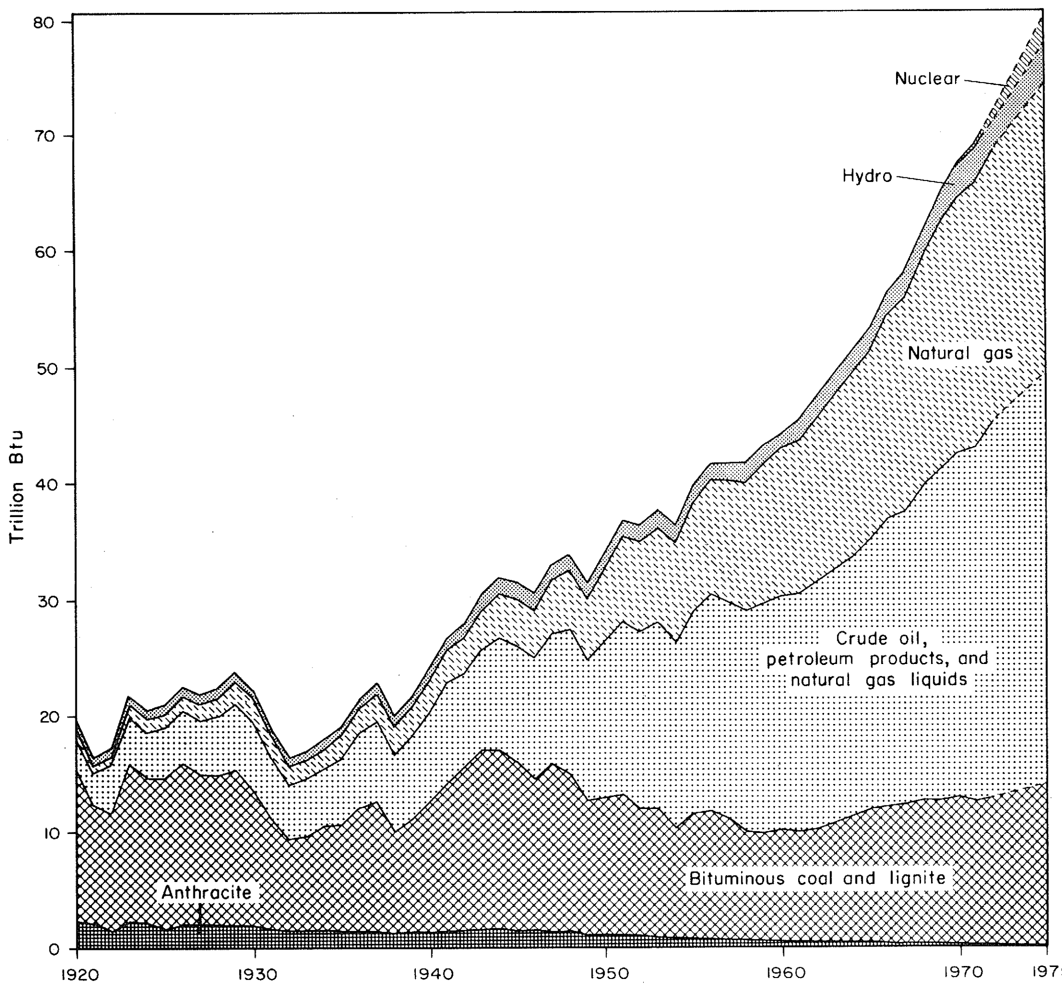


Fig. 2 - Trends in energy consumption in the United States, 1920-1975. Actual data used for 1920-1971 period; projection to 1975 based on projected energy consumption patterns in 1975 given by Dupree and West (1972, p. 50).

more than 29 percent of the total petroleum supply during the year came from foreign sources (U. S. Bur. Mines, 1973b, p. 2). Three years earlier, in 1969, imports had accounted for only 22.4 percent of the total petroleum supply (U. S. Bur. Mines, 1971, p. 2). About 5 percent of the natural gas consumed in 1972 also was imported. Essentially all of the coal consumed was from domestic sources.

The 1972 level of energy consumption was 4.9 percent higher than that of the previous year, continuing the high rate of growth that has occurred in the past and is projected for the future. Figure 2 shows the rise in the use of energy since 1920 and the changes in the relative shares provided by each of the major sources. The projected level of energy consumption for 1975 shown in figure 2, based on a projection by the U. S. Department of the Interior for that year, also is shown on the chart (Dupree and West, 1972, p. 17).

Figure 3 shows the decline in the relative contribution of bituminous coal and anthracite to total energy consumption in comparison with the steadily increasing contribution by petroleum and natural gas. Although nuclear power has experienced very rapid growth in recent years, in 1972 it still accounted for less than one percent of the total energy consumed.

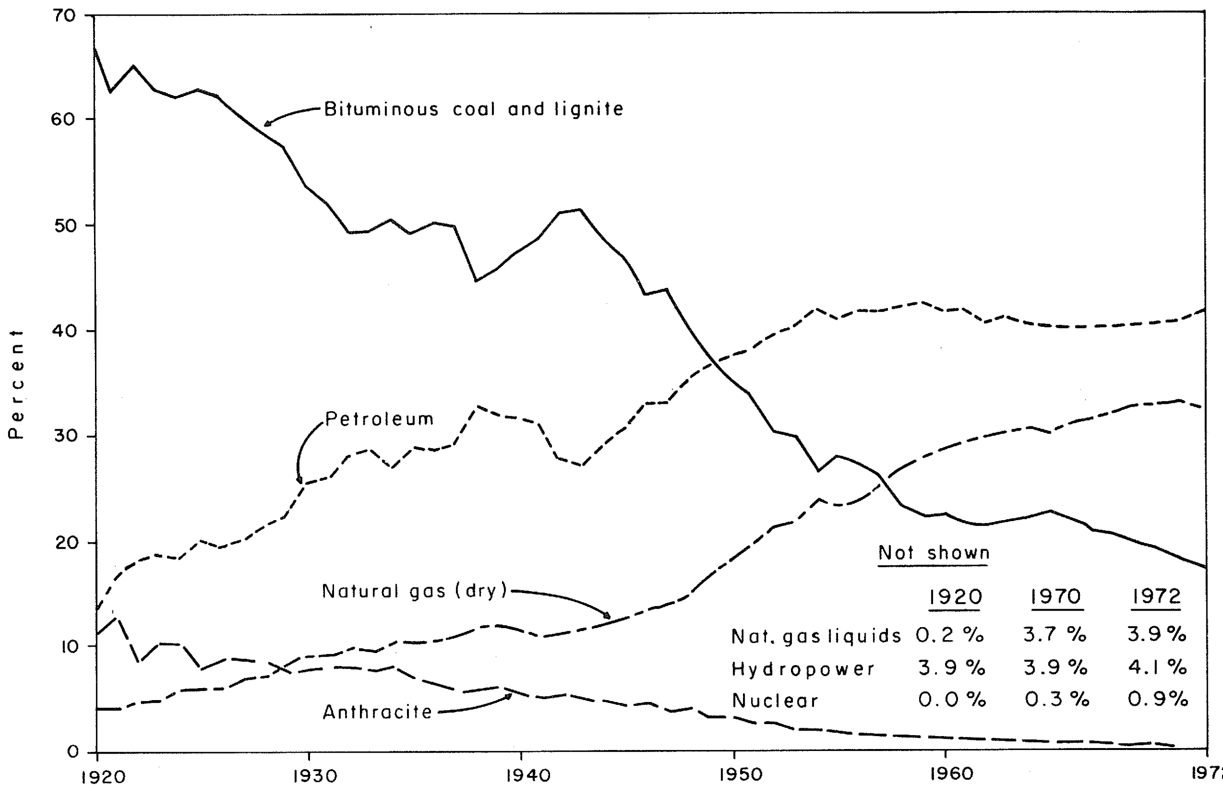


Fig. 3 - Share of total energy consumed contributed by primary energy sources, 1920-1972.

Limitations to Productive Capability

At the beginning of 1973, most of the fuel and energy-producing sources of the United States, with the possible exception of coal, were contributing at or near the full limit of their developed capacity. Limitations encountered for each fuel are discussed, following.

Natural Gas

Production of natural gas in the United States grew from 5.6 trillion cubic feet in 1947 to an estimated 22.9 trillion cubic feet in 1972, a more than 4-fold increase in 25 years (Am. Gas Assoc. et al., 1972, p. 120; Petroleum Engr. Internat., 1973, p. 1).

The output in 1947 was equal to only 3.5 percent, or less than one-twenty-ninth, of the natural gas reserves available at the beginning of that year. In 1972 the output was 9.1 percent, or one-eleventh, of available reserves, despite the fact that the actual amount of reserves was 58 percent greater than in 1947.

Trends in natural gas production and in those proved reserves that are currently available for production are shown in figure 4. Because the estimated 26 trillion cubic feet of reserves in the Prudhoe Bay area on the North Slope of Alaska cannot at present be considered available, they are not included in the figure. Reserves in southern Alaska, from which gas currently is being produced, are included.

Estimated reserves at the end of 1946 were 159.7 trillion cubic feet. From 1947 through 1971 new additions to reserves (excluding the Alaskan North Slope) ranged from 8.4 to 24.7 trillion cubic feet per year and totaled 411 trillion cubic feet for the 25-year period. Each year through 1967 the annual additions exceeded production and reserves continued to increase, reaching a peak level of 293 trillion cubic feet in that year (fig. 4). However, during each of the 5 succeeding years, 1968 through 1972, production exceeded new additions, and total reserves declined from 293 trillion cubic feet to 240.1 trillion (Petroleum Engr. Internat., 1973). The 1972 production of almost 23 trillion cubic

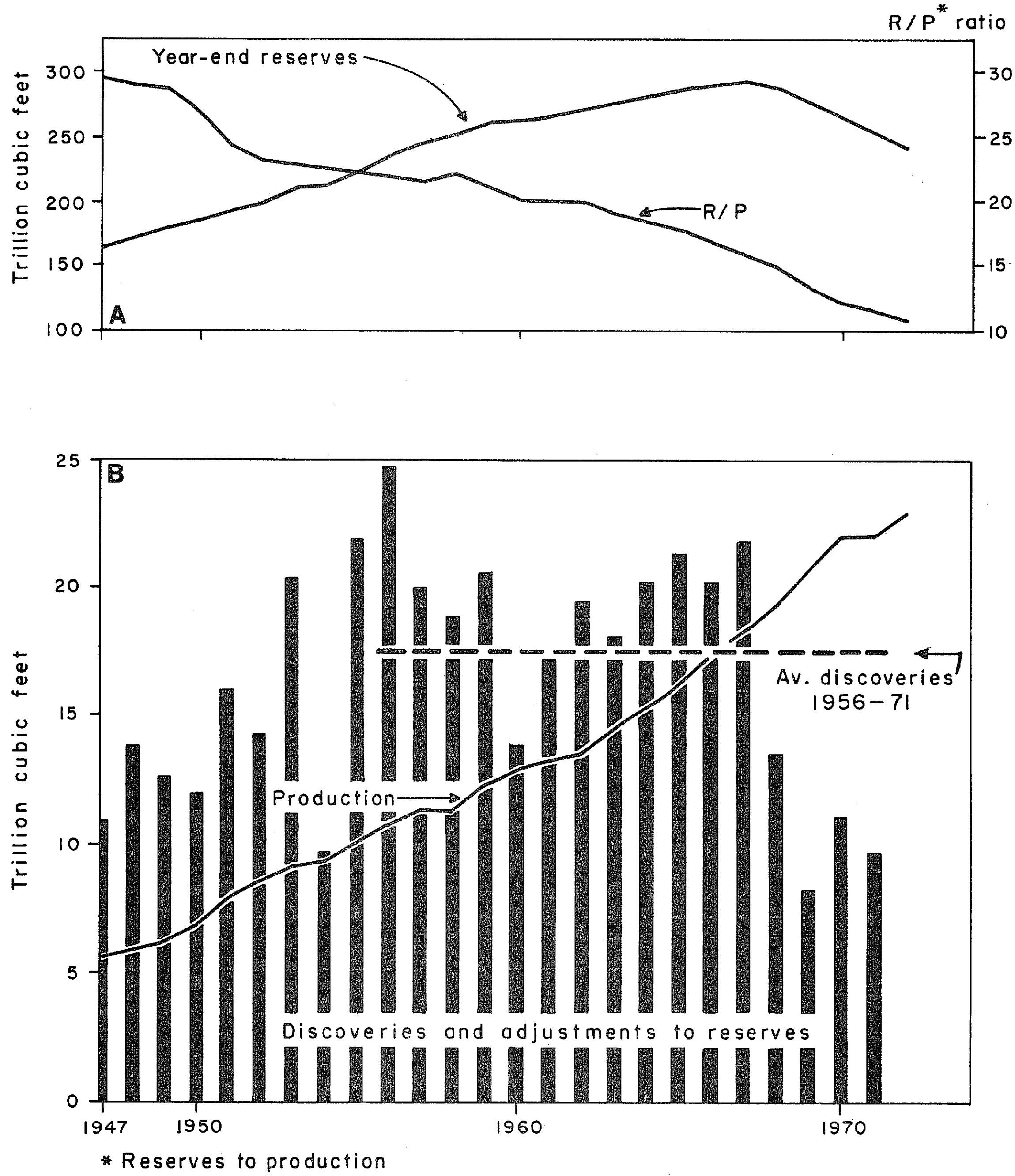


Fig. 4 - A. Natural gas reserves (excluding Alaskan North Slope) and the R/P (reserves-to-production) ratio, 1947-1971. B. Natural gas production and annual discoveries and adjustments (additions) to reserves, 1947-1971.

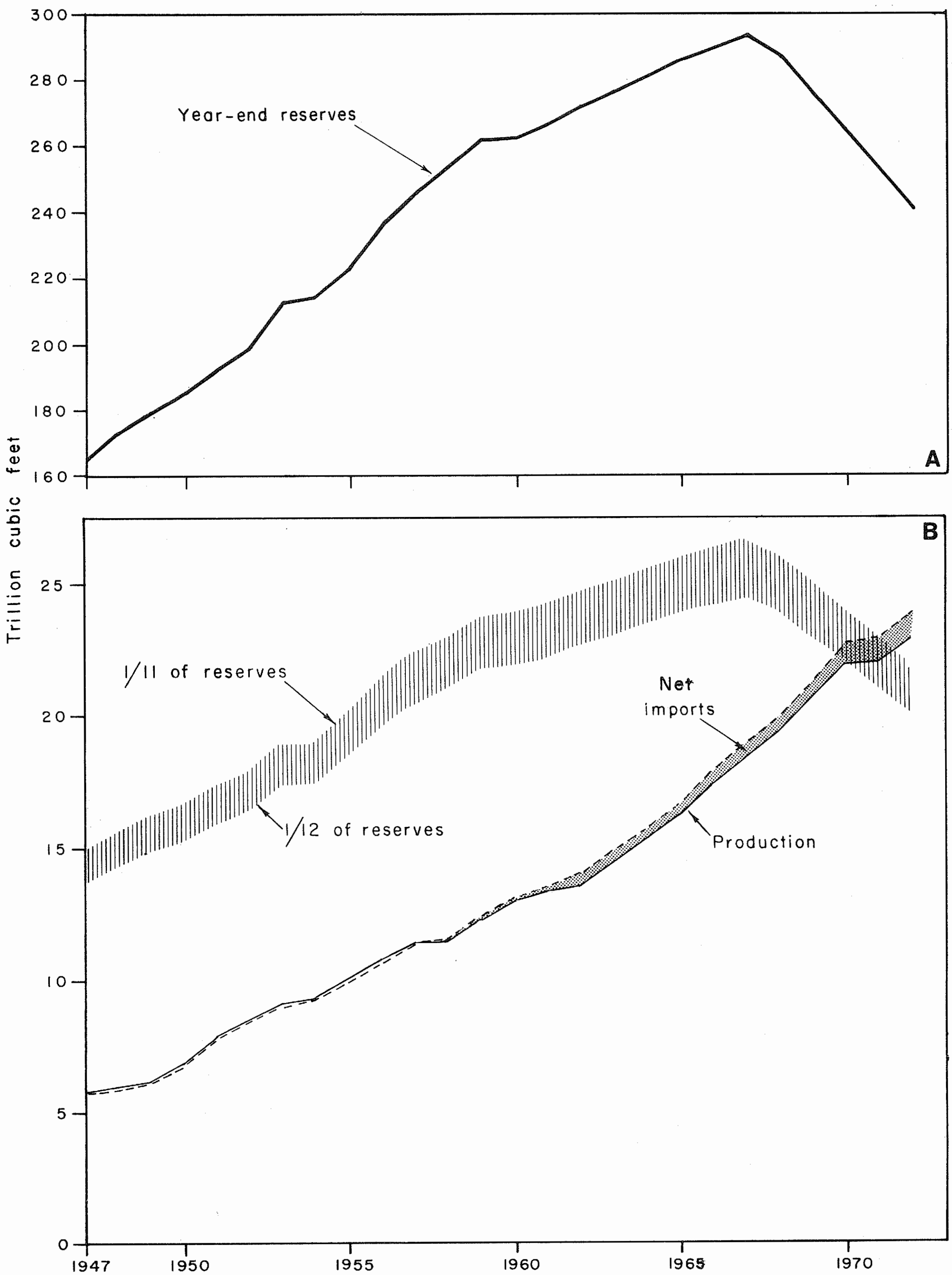


Fig. 5 - A. Year-end reserves of natural gas, excluding Alaskan North Slope reserves, 1947-1971. B. Production and net imports of natural gas, 1947-1971. Lined zone indicates range of maximum productive level achievable with the reserves shown.

feet was an amount greater than the additions to reserves in any previous year, with the exception of the record 24.7 trillion cubic feet added in 1956. The average annual rate of additions for the 16 years from 1956 through 1971 was 17.5 trillion cubic feet, much less than the 22.9 trillion used in 1972.

More important to productive capability than the absolute level of either reserves or production is the ratio of the reserves to the annual production, commonly called the R/P ratio. The rate at which gas and oil can be produced from proved reserves at any given time without loss of ultimate recovery is influenced by many factors, among which are the nature of the reservoir rock, the reservoir pressure, the extent of development and spacing of wells, and the stage reached in the development and productive life of the reservoir. Although no specific average figure is necessarily appropriate for any given reservoir or field at any given time, experience has indicated that the minimum R/P ratio at which a given level of production can be maintained is about 11 or 12 to 1 for the total natural gas reserves of the United States. The R/P ratio for natural gas in the United States declined from about 29.5 to 1 in 1947 to less than 11 to 1 in 1972 (fig. 4). As the R/P of 11 was approached, there was a distinct leveling-off in the rate of growth in production, despite a continuing strong demand, because the optimum level of production had nearly been reached.

Figure 5 shows trends in natural gas consumption, domestic production, net imports, and the domestic reserves of natural gas (exclusive of the Alaskan North Slope). Also shown is the range of 1/11 to 1/12 of these reserves, as an approximation of the upper limit of quantity producible on a sustained basis. Although this range may not accurately represent the exact limits of producibility in past years, the diagram illustrates how the limit of producibility has been overtaken as growing demand outran new discoveries. Until the decline in the R/P ratio is reversed by a significant increase in reserves, little or no further increase in productive capacity can be anticipated.

Liquid Fuels

Liquid fuels consumed in the United States are obtained from crude oil and from natural gas liquids, which include condensate as well as liquids from natural gas plants. Refined products from crude oil constitute about 80 percent of the liquid fuels total.

The trends in crude oil production and crude oil reserves in the United States (exclusive of the Alaskan North Slope) are shown in figure 6. The figure also shows a range between 1/7 and 1/8 of the known recoverable reserves, estimated as the approximate upper limit of producibility for petroleum. As was true for natural gas, this range is approximate rather than absolute because there is no way of determining the absolute limit without actually reaching it. The leveling-off of production from 1970 to 1972, despite the lifting of prorationing restraints, is a strong indication that the productive capacity of available reserves has been reached. An additional increment of capacity, amounting to an estimated 0.5 to 0.75 million barrels per day, or 180 to 275 million barrels per year, does exist in the Elk Hills Naval Petroleum Reserve and other areas, but for various reasons these reserves are currently unavailable for production (Natl. Petroleum Council, 1971, p. 30).

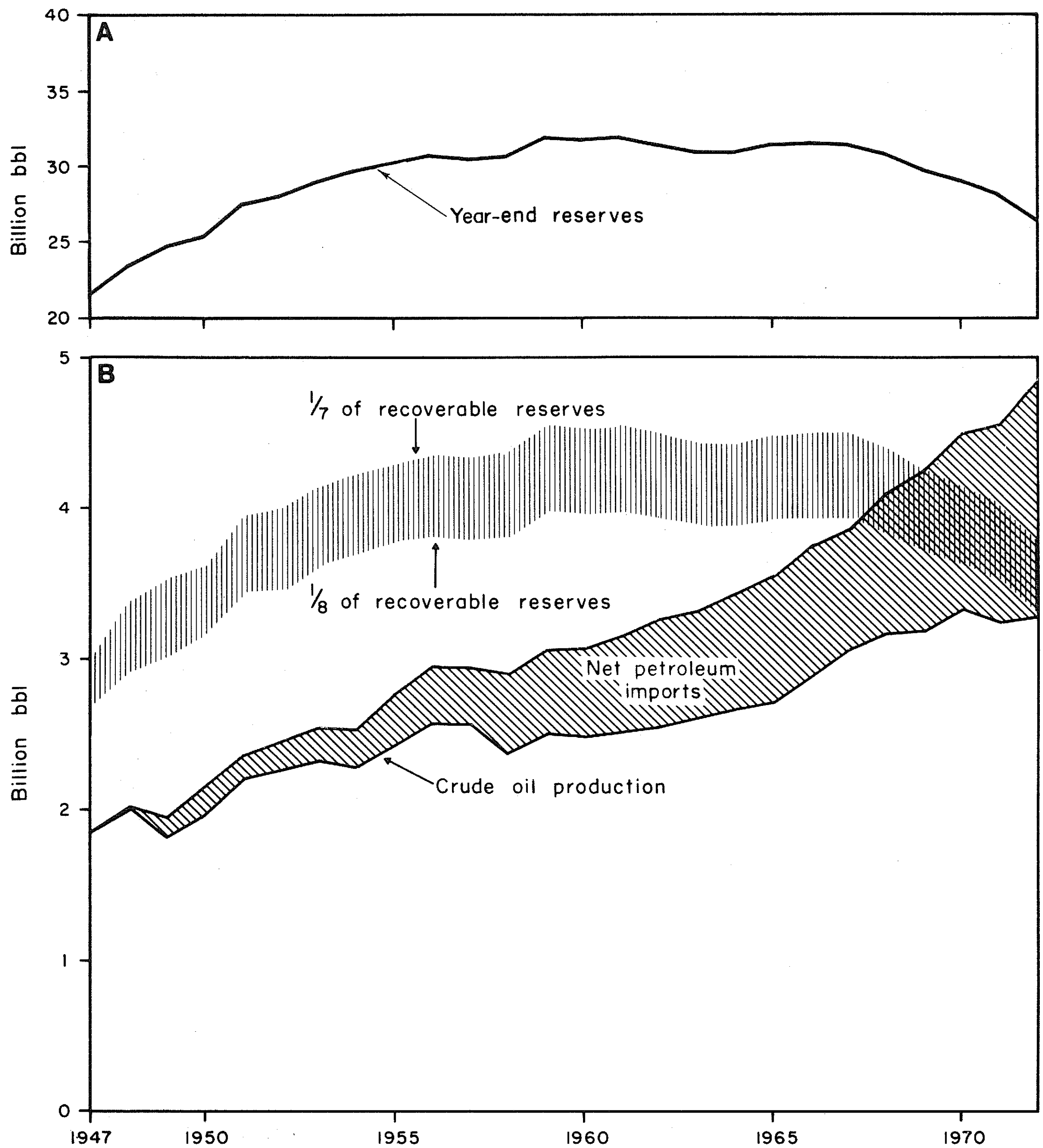


Fig. 6 - A. Year-end reserves of crude oil, excluding Alaskan North Slope. B. Domestic crude oil production and net imports of crude oil and refined products, 1947-1971. Vertical-lined zone indicates range of maximum productive level achievable with the petroleum reserves shown.

The American Petroleum Institute annually estimates the "90-day productive capacity," which is defined (Am. Gas Assoc. et al., 1972, p. 20) as the

> ...maximum daily crude production rate, at the point of custody transfer, that could be achieved in 90 days (following December 31 of any given year) with existing wells, well equipment, and surface facilities—plus work and changes that can be reasonably accomplished within the time period using present service capabilities and personnel and with productivity declining as it would under capacity operation.

The estimate of the daily productive capacity of crude oil in the United States attainable after the 90 days immediately following December 31, 1970, was 11,173,000 barrels; following December 31, 1971, it was 10,649,000 barrels (Am. Gas Assoc. et al., 1972, p. 76). These estimates indicate a productive limit of 1:7.3 to 1:7.5 of the reserves, or about the middle of the range shown in figure 6.

When liquid fuels are examined as an energy source, crude oil and natural gas liquids must be considered together. Natural gas liquids are defined (Am. Gas Assoc. et al., 1972, p. 221) as:

> ...the hydrocarbon components: propane, butanes and pentanes plus (also referred to as condensate), or a combination of them, that are subject to recovery from raw gas liquids by processing in field separators, scrubbers, gas processing and reprocessing plants, or cycling plants. The propane and butane components are often referred to as liquefied petroleum gases or LPG.

Because natural gas liquids are produced jointly with crude oil and natural gas, their output, too, has approached a ceiling until greater oil and gas productive capacity is attained. Figure 7 shows the reserves and the production of total liquids, including both crude oil and natural gas liquids. Reserves have been declining since 1967, closely paralleling the decline in reserves of both crude oil alone and natural gas.

Until 1967, annual additions to domestic reserves of crude oil and natural gas liquids exceeded production, and reserves rose steadily (fig. 7), although reserves of crude oil alone had leveled off several years earlier (fig. 6). After 1967, the combined reserves began to decline, and from the end of 1967 to the end of 1972 they fell by 17 percent. The calculations do not include the Alaskan North Slope reserves.

Until 1948 the United States was a net exporter of oil, but since then it has become a net importer of increasing amounts of crude oil and refined petroleum products (fig. 7). Until 1968, estimated unused capacity would have been essentially sufficient to replace imports had there been an interruption in supplies from foreign sources, although there would have been some time lag in bringing this capacity into production. By 1968, total consumption was exceeding capacity by an increasing margin, and by 1972 the capability of increasing annual output to any degree from proved reserves was virtually nonexistent.

The United States demand for liquid petroleum products in 1972, according to preliminary reports, was 5985.6 million barrels, compared to 5552.6 million barrels in 1971, an increase of 433 million barrels (U. S. Bur. Mines, 1973b, p. 2). Of this 433-million barrel increase, 302 million barrels, or 69.7 percent, came from increased imports, including an increase of 86 million barrels of imported refined products. Only 20 million barrels of the total increase came from increased domestic production.

Part of the supply for increased consumption in 1972 came from a decrease in inventory stocks. The decline in stocks during 1972 amounted to 86 million barrels. That the decline was still continuing into 1973 is indicated by the fact that inventories of petroleum and natural gas liquids were 97 million barrels lower at the end of February 1973 than they had been 12 months earlier (U.S. Bur. Mines, 1973c, p. 2).

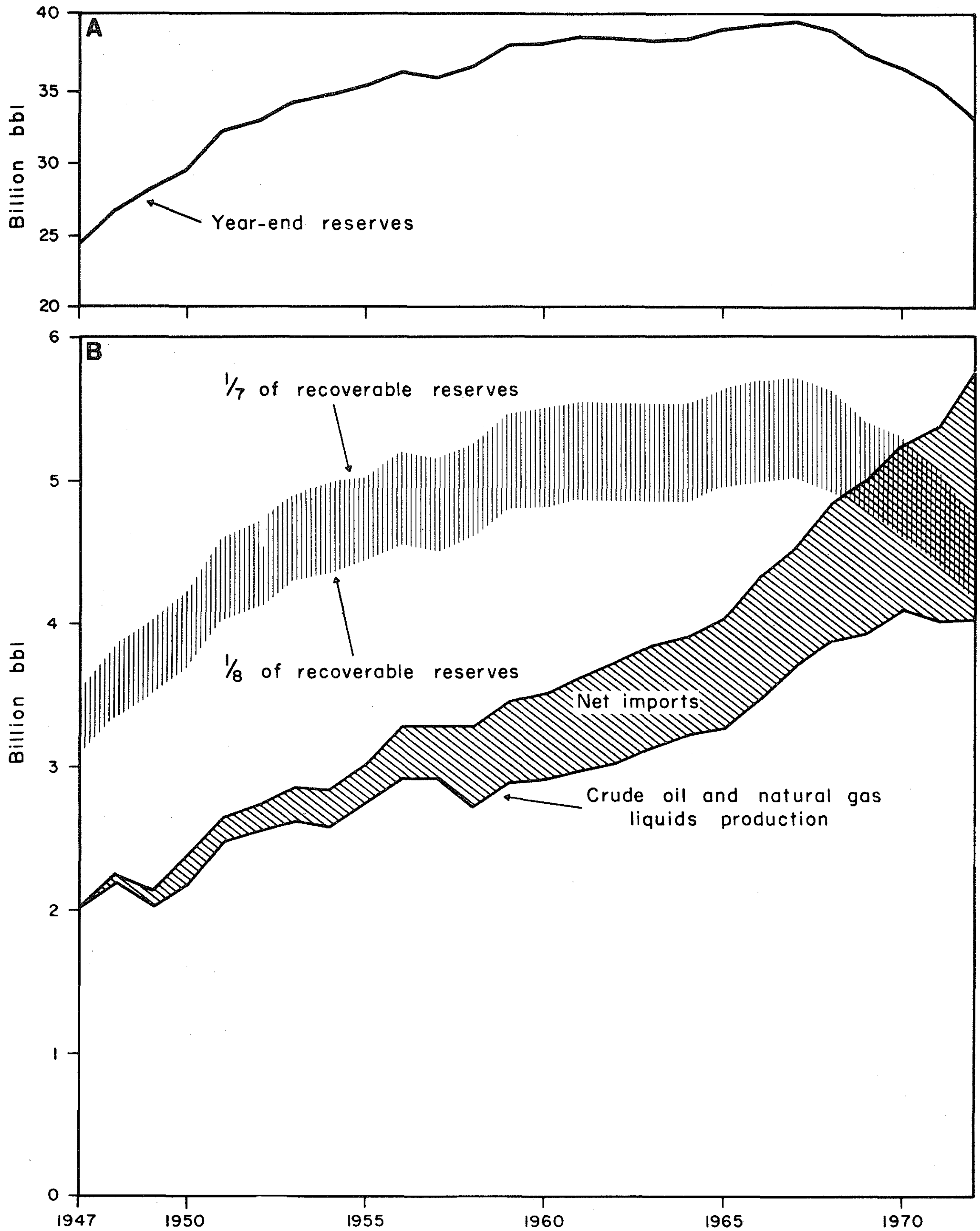


Fig. 7 - A. Year-end reserves of crude oil and natural gas liquids, excluding Alaskan North Slope. B. Net oil imports and production of crude oil and natural gas liquids, 1947-1971. Vertical-lined zone shows range of maximum productive level achievable with reserves shown in A.

In recent years an increasing share of crude oil imports has come from Africa and the Middle East. Imports of crude oil in 1972 totaled 198 million barrels more than in 1971, with 53 percent of the increase coming from Africa, 16 percent from the Middle East, and only 22 percent from the Western Hemisphere. The remaining 9 percent came primarily from Indonesia (U.S. Bur. Mines, 1973b, p. 17). Imports from Africa and the Middle East, therefore, are growing three times as fast as imports from nearer sources, such as Canada and South America.

Coal

The current output of coal, unlike that of oil and gas, is not restricted by the lack of identified recoverable deposits. An estimated 200 billion tons of recoverable coal in beds 42 inches or more thick is known to occur at depths within a thousand feet of the surface (Theobald et al., 1972, p. 3). These resources are within the range of conditions under which coal is currently being mined and could yield an estimated 330 times the 1972 level of coal production.

Although there is no lack of identified coal reserves, the capability for production at any given time is limited by a number of other factors, including the number and capacity of existing mines, manpower availability, the supply of railroad cars, and environmental considerations. Although all of this coal could provide greatly needed energy, much of it cannot be used in present combustion facilities without exceeding currently acceptable levels of sulfur oxide emission.

The production, consumption, and exports of United States coal have varied widely from year to year, as shown in figure 8. A surplus of mine capacity has normally existed, and, except in times of strikes, scarcity of railroad cars, or exceptional demands caused by war or other unusual circumstances, shortages of coal have rarely occurred. No completely accurate determination of the total coal-producing capacity can be made. However, estimates based on the annual output and the average number of days worked by the mines during the year can be made. The U. S. Bureau of Mines makes estimates each year of the amount of coal that could be produced if all mines operated 280 days per year at the average rate of daily output indicated by the year's actual production and average number of days worked. As full operation for more than 250 days per year is highly unlikely for most mines, the Bureau of Mines 280-day estimates are reduced to a 250-day basis in figure 8. The indicated percentage of surplus capacity has obviously declined drastically during the past 15 years.

A recent factor affecting the capacity of existing mines has been the major decline in manpower productivity in underground mines since the enforcement of new mine safety rules and regulations based on the Federal legislation of December 30, 1969. Output per man-day declined from 15.61 tons in 1969 to 12.03 tons in 1971, a 23 percent drop (U. S. Bur. Mines, 1973d, p. 4). This decline in productivity was related primarily to changes made in operating procedures to comply with the new rules.

The decline in productive capacity and some of its implications were pointed out recently by T. Reed Scollon, Chief of the Division of Fossil Fuels, U. S. Bureau of Mines (Scollon, 1973, p. 101):

> As distinguished from the past, there is no longer any surplus productive capacity of consequence in the industry. This situation has developed as a result of the closure of many underground mines and various deterrents to large-scale investments in additional coal-producing capacity. Announcements in 1972 of planned new coal mining capacity were at the lowest level in years. Most new eastern United States capacity is for metallurgical use. On a national basis, the new tonnage will not be sufficient to replace depleted capacity.

Deterrents to new capacity development in 1972 included increasing oil imports, continuing uncertainties with respect to the timing and extent of nuclear power generation, existing and proposed environmental restrictions against coal, and price controls.

The evidence leads to the conclusion that while some capacity for increased production of coal may exist, the amount of increase that could be realized from existing installations and facilities is relatively small.

In addition, the sulfur dioxide emission standards proposed by a number of states for 1975 and beyond will disqualify from future use much of the coal from currently available sources. Should these standards go into effect as scheduled and the burden of supplying needed coal energy be placed on low-sulfur coal alone, the capacity for producing it will be inadequate.

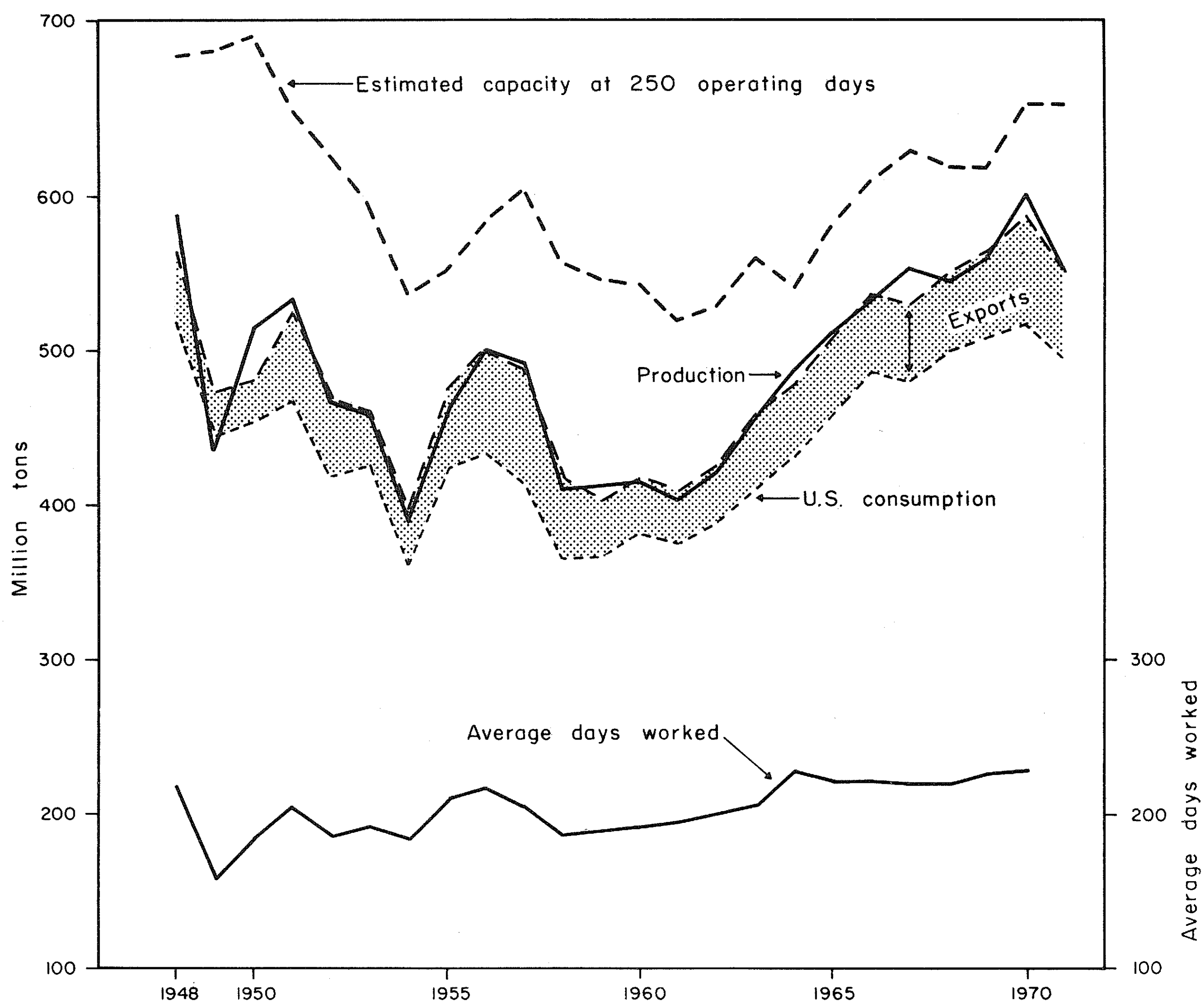


Fig. 8 - Production, consumption, and exports of U.S. coal, 1948-1971. Average days worked and estimated annual total capacity of U.S. coal mines, assuming 250 operating days per year, also are shown.

Hydroelectric Power

Hydroelectric power has for the past several decades provided approximately 4 percent of the total energy consumed within the United States each year (fig. 9). The hydroelectric plants of the nation operate at essentially optimum capacity, limited only by water availability, variations in demand, and the interruptions or shutdowns required for maintenance. During the spring of 1973, significant cutbacks in power generation in the Pacific Northwest to a level below the normal capacity of the installed generating equipment became necessary because of water shortages. Reductions and interruptions in power to consumers resulted, especially power provided to those industrial customers who purchase on an interruptible basis. The impact of the curtailment was described by *The Wall Street Journal* (1973a):

> Bonneville Power's hydroelectric shortage stems from low stream flow due to poor conditions for melting snow pack in the Columbia River basin. Its curtailment, amounting to 50 percent of power that would go to industrial users on an "interruptible" basis, is hitting aluminum companies especially hard because the area has the nation's largest concentration of smelters, which require enormous amounts of electricity to make primary metal.

Although the annual output of electricity from hydroelectric plants has increased 90 percent since 1960, hydropower's share of the total amount of electricity generated has declined (fig. 9B). Little, if any, increase in hydroelectric power is possible from existing plants at the present time to help alleviate the energy shortage.

Nuclear Power

The generation of electric power by nuclear power plants increased more than tenfold between 1964 and 1972 (fig. 9A). However, the actual amount of power generated in 1972 still represented only 3 percent of total electric power output. Although development of nuclear power is being pushed ahead as fast as possible, numerous problems are limiting both the rate of expansion of new capacity and the output from existing nuclear facilities. Recent articles have pointed out some of the problems that have retarded the completion of the plants currently under construction and the full operation of plants already completed (Ehrich, 1973, p. 1). Causes cited include problems related to engineering design, mistakes in assembly, failures of materials, defective fuels, and delays in construction of plants and in fabrication of units.

Geothermal Power

The only sizable geothermal electric power generating units operating in the United States in 1972 were at The Geysers, about 90 miles north of San Francisco, California. They have a combined capacity of 290 megawatts. Although a major expansion in the use of geothermal energy has been forecast, the capacity of existing facilities is being fully utilized, and greater use of geothermal energy potential must await further exploration and development.

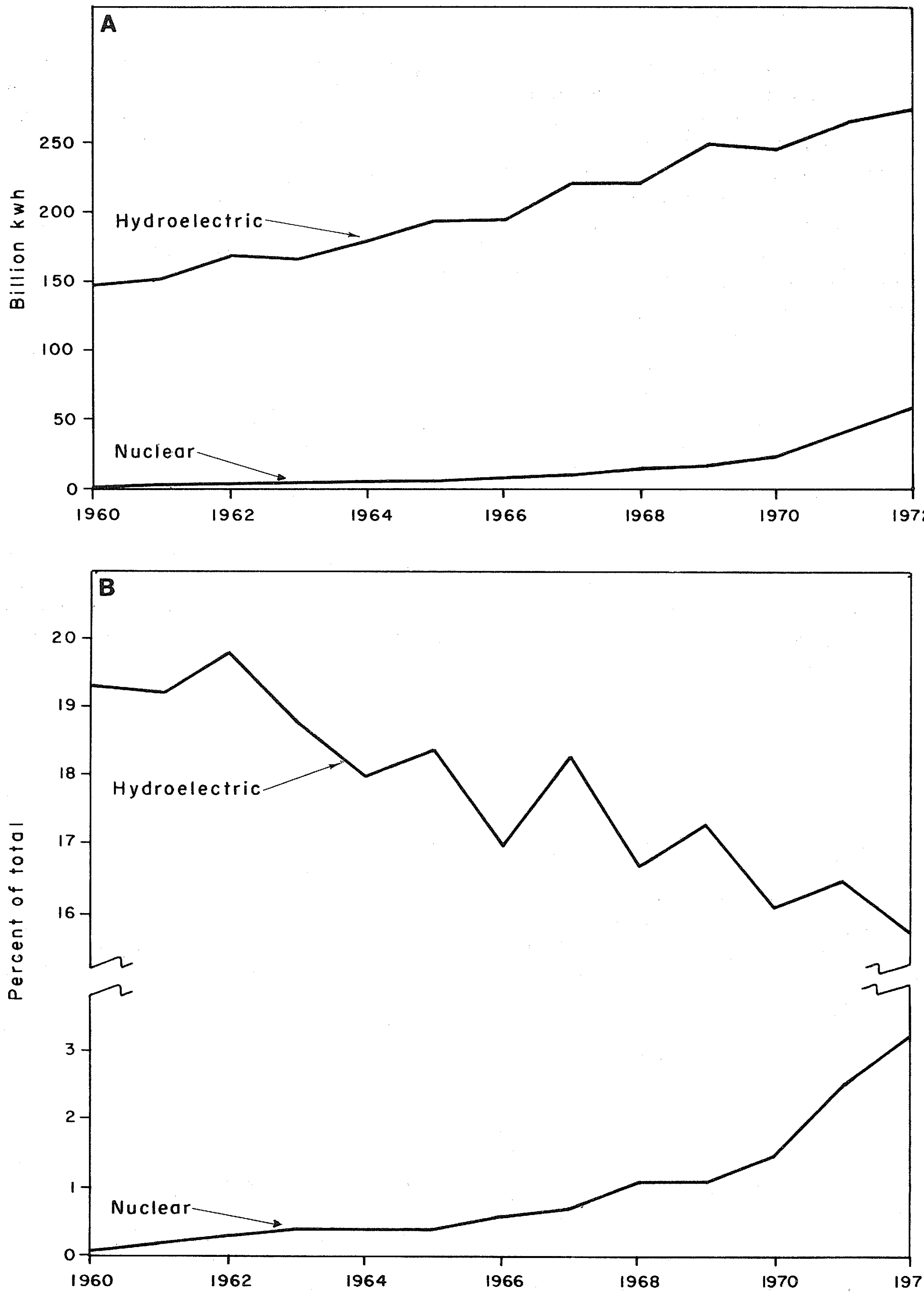


Fig. 9 - A. Electric power output by utilities from hydroelectric and nuclear plants. B. Percentage of total electric power output of utilities that is provided by hydroelectric and nuclear plants.

International Problems and Complications

With domestic oil and gas wells producing at capacity, no significant surplus coal-producing capacity, and no means of rapidly expanding the energy output from other domestic sources, the United States currently has no choice but to increase its imports of oil and refined products. In 1972 imports provided about 29 percent of the nation's total liquid fuel supply (U. S. Bur. Mines, 1973b, p. 2), and liquid fuels accounted for 45.5 percent of all the energy used within the country. In addition, about 5 percent of the natural gas consumed was imported, most of it by pipeline from Canada (U. S. Bur. Mines, 1973a, p. 4, 6).

The importation and use of foreign materials is not, of itself, necessarily undesirable; some highly industrialized nations are largely dependent on imports for the bulk of their raw materials. However, the dependence of the United States on foreign sources for so much of its energy supply does carry with it serious implications from both economic and national security standpoints.

Economic Implications

The United States suffered serious balance of payment problems in 1972, leading to international monetary difficulties and the devaluation of the dollar. Among the contributing factors was the dollar outflow to pay for increased fuel imports. The dollar value of United States fuel imports and exports in 1972 (U.S. Dept. Commerce, 1973, p. S22-S23) was as follows:

	Billion dollars	
	Imports	Exports
Total mineral fuels	4.799	1.554
Petroleum and petroleum products	4.300	0.445
Coal and related products	not available	1.019

Figure 10 shows the rapidity with which the value of fuel imports has been rising—and contributing to the balance of payments problems. The major part of the total fuel export value is accounted for by coking coal exports to Europe, Japan, and Canada. Of the total value of fuel imports in 1972, almost 90 percent was for petroleum and petroleum products. Most of the remainder was for natural gas imported from Canada.

The net U.S. deficit in petroleum trade in 1972 amounted to $3.85 billion. This deficit not only contributed in some degree to the difficulties leading to devaluation of the dollar, but the devaluation of the dollar, in turn, led to higher prices for foreign oil purchases. The increasing import value shown in figure 10 thus results from a combination of increased quantities of imports, increased prices as a result of supply and demand factors, and a still further increase in prices resulting from the dollar devaluation. The projected shortage of domestic fuel and the accompanying need for increased imports make it certain that U. S. foreign trade deficits for energy-producing materials will continue to rise rapidly. Some estimates indicate that the value of oil imports will reach nearly $10 billion per year by 1975 and approach $20 to $25 billion per year by the early 1980s (Oil and Gas Jour., 1973b).

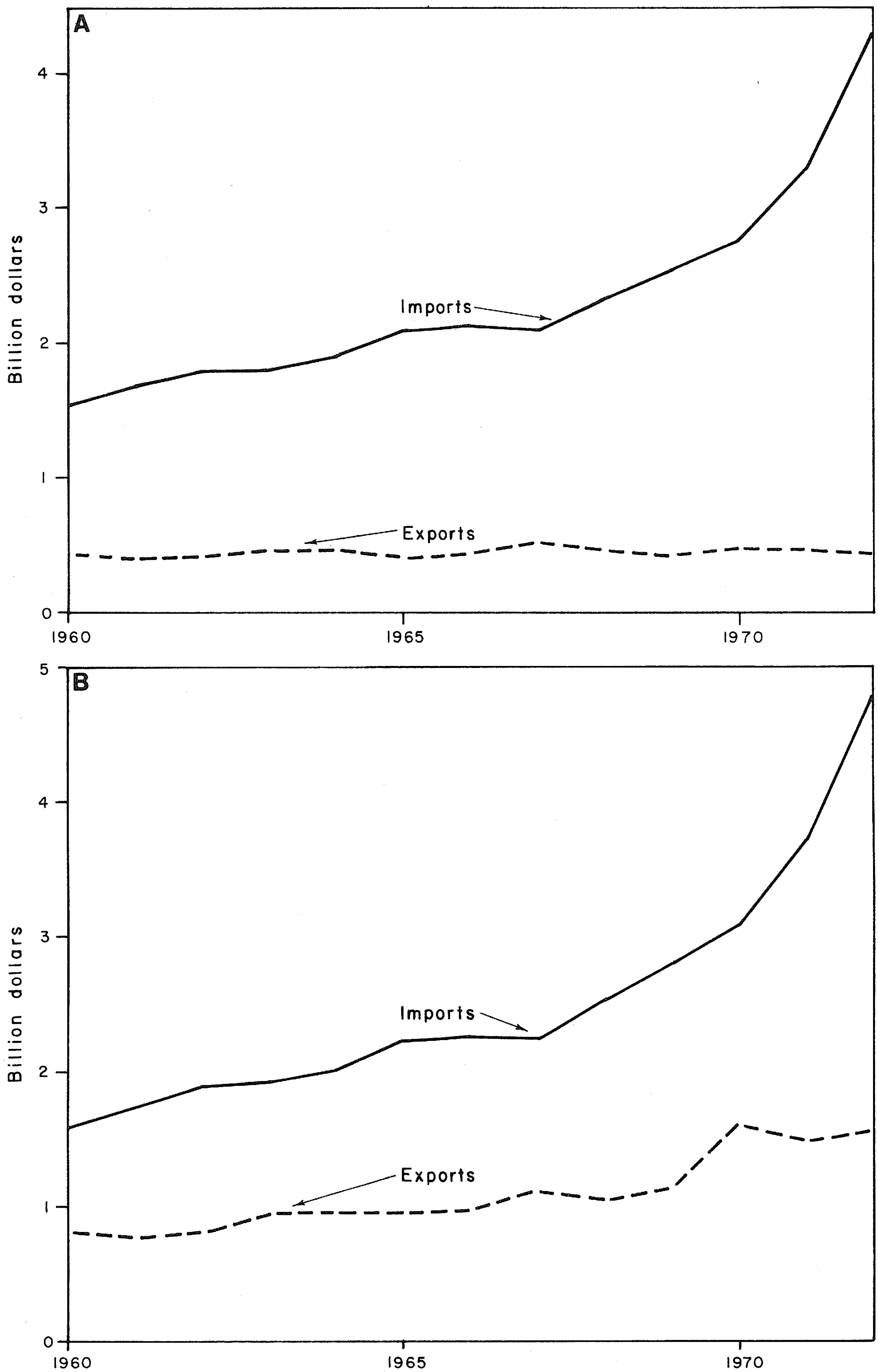


Fig. 10 - United States foreign trade in mineral fuels: A—Crude petroleum and petroleum products. B—Total fuels, 1960-1972.

Grave concern is being expressed for the danger of currency speculation and disruption of monetary stability that could occur from a great outflow of money for oil imports that is not balanced by increased exports. The total amount of money expended for the purchase of oil, mainly from the Middle East, by the oil-importing nations in the 12 years from 1961 through 1972, is reported to be $27 billion. Estimates indicate that for the 12 years beginning in 1973, the total may reach $227 billion. If a significant portion of this money were to be used for monetary speculation, rather than expended for purchases or channeled into investment, the impact on the currencies of oil-importing countries could be disastrous (Oil and Gas Jour., 1973a).

National Security

From the standpoint of the national security of the United States, dependence on foreign sources for a large part of our energy needs, especially on those sources outside the Western Hemisphere, could be accompanied by serious problems of several types. First, such oil supplies could be interrupted at the source through any of a variety of circumstances beyond the control of the United States; second, international competition for the available supplies is increasing; and, third, large numbers of tankers traveling sea lanes that are thousands of miles long would be highly vulnerable to any hostile action that might occur. As the more distant of the sources of supply become increasingly important, the significance of each of these potential problems grows.

Figure 11 shows trends in the domestic production of crude oil and natural gas liquids in the United States and in imports of both crude oil and refined products. During the 10-year period shown, United States crude oil production increased only 26 percent, while imports of both crude oil and refined products doubled. Imports as a percentage of the total liquid fuel supply grew from about 19 percent in 1963 to about 29 percent in 1972.

Most of the imported refined products come from the Western Hemisphere, primarily South America and the Caribbean area. An increasing portion of crude oil imports, however, is coming from more distant sources in Africa and the Middle East (fig. 12). Imports from Africa and the Middle East increased from 31.1 percent of total crude imports in 1966 to 40.4 percent in 1972. During this 6-year period, however, two major interruptions in shipments have occurred. Middle Eastern shipments declined abruptly in 1967 (fig. 12) from the effects of the Arab-Israeli conflict. In 1970, imports from North Africa fell sharply as a result of Libya's decision to reduce its oil production. During that same year the growth in imports from the Middle East was slowed when, on May 3, 1970, a bulldozer broke the Trans-Arabian pipeline that runs from Saudi Arabia across Syria to the Mediterranean port of Sidon, Lebanon. The flow of 475,000 barrels per day of crude oil was halted for several months before repair of the pipeline was permitted by the Syrian government.

At the time of the 1967 and 1970 interruptions in the flow of imports, the United States still had some surplus oil-producing capacity; therefore, domestic crude oil output could be increased to help compensate for the reduction in imports (figs. 7 and 11). Today this surplus capacity no longer exists, and similar interruptions of supplies could be much more serious.

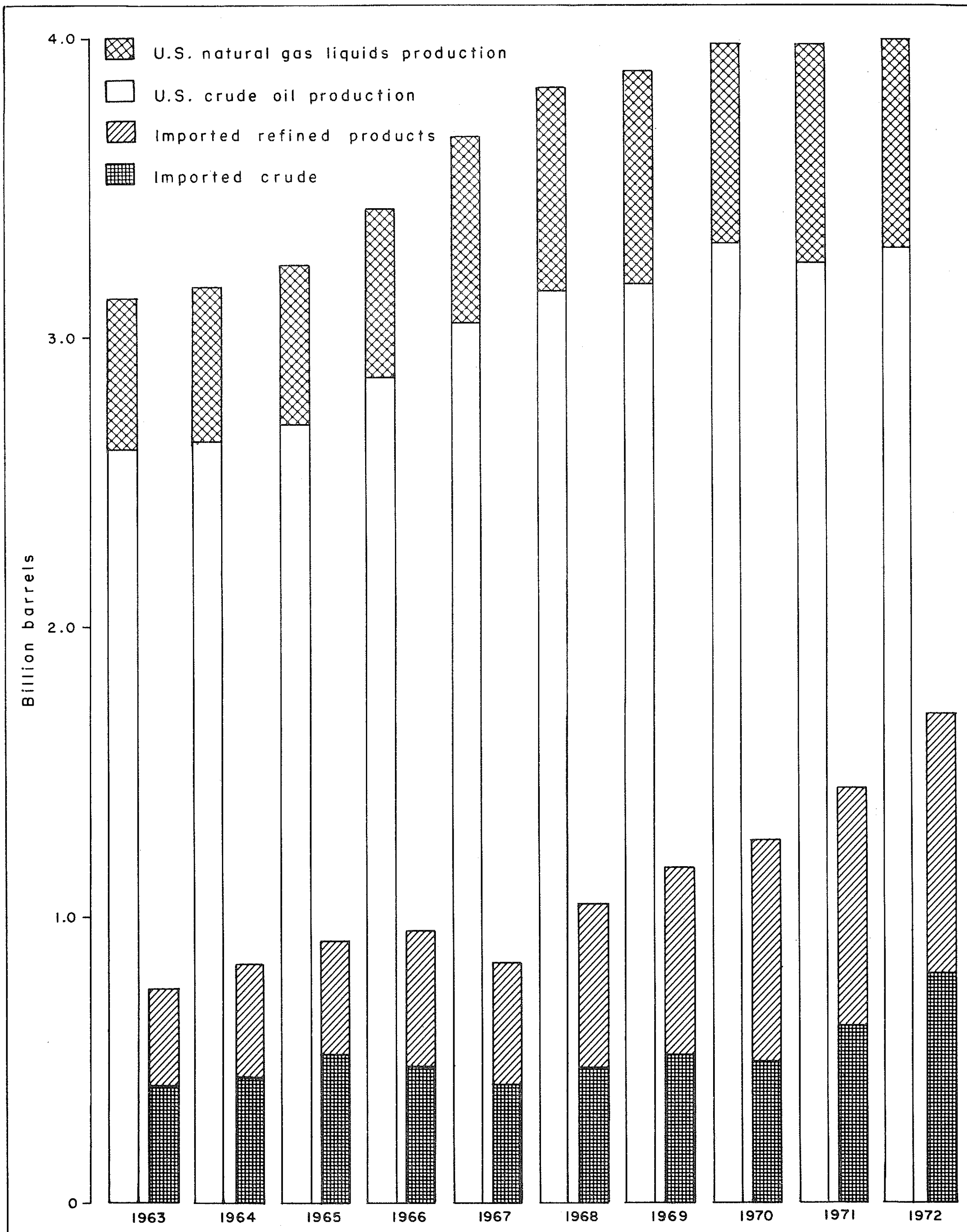


Fig. 11 - Domestic production of crude petroleum and natural gas liquids and imports of crude petroleum and refined products, 1963-1972.

In recent years there has been an increasing trend to import oil, especially crude oil, from sources outside the Western Hemisphere (fig. 12). From 1963 through 1972, total annual imports from the Western Hemisphere increased by 51 percent; imports from the Eastern Hemisphere, primarily the Middle East and North Africa, increased 191 percent. A 47 percent decline in crude oil imports from Venezuela during this period was more than offset by a trebling of imports

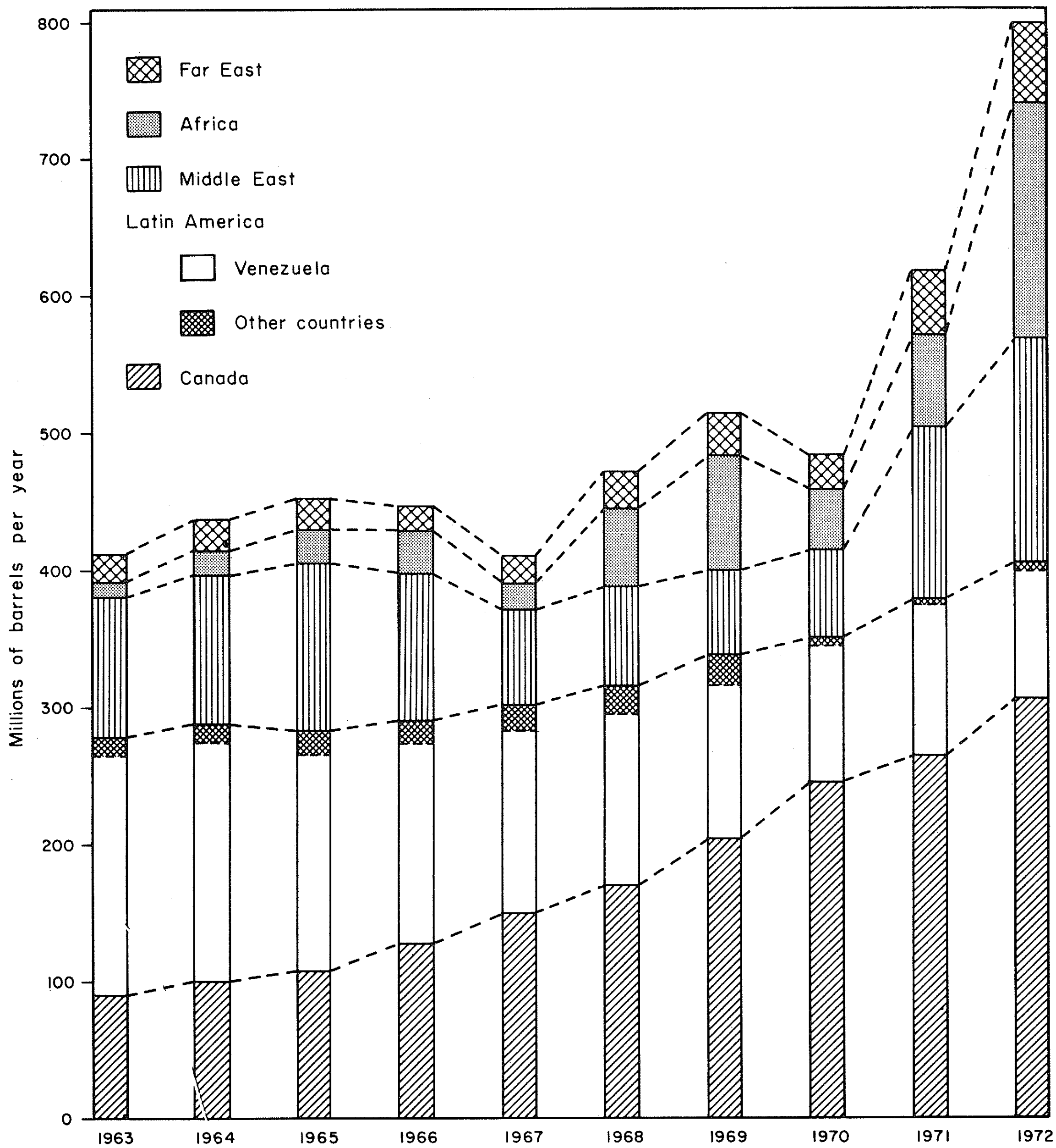


Fig. 12 - Crude oil imports into the United States, by source area or country, 1963-1972. Data for 1972 are preliminary.

from Canada. Canada has recently announced plans to limit the rate of growth of oil exports, an action that is likely to increase further our need for Eastern Hemisphere oil. Studies by the National Energy Board of Canada already have indicated, "...production from all sources in Canada will not be able to meet the potential export and domestic market demand after 1973" (Oil and Gas Jour., 1973b, p. 40).

As the United States increases imports from the Eastern Hemisphere, competition with those other industrialized nations of the world that also lack self-sufficiency in oil will be more acute. More than half of the world's known crude reserves lie within the Persian Gulf region, which provides more than 30 percent

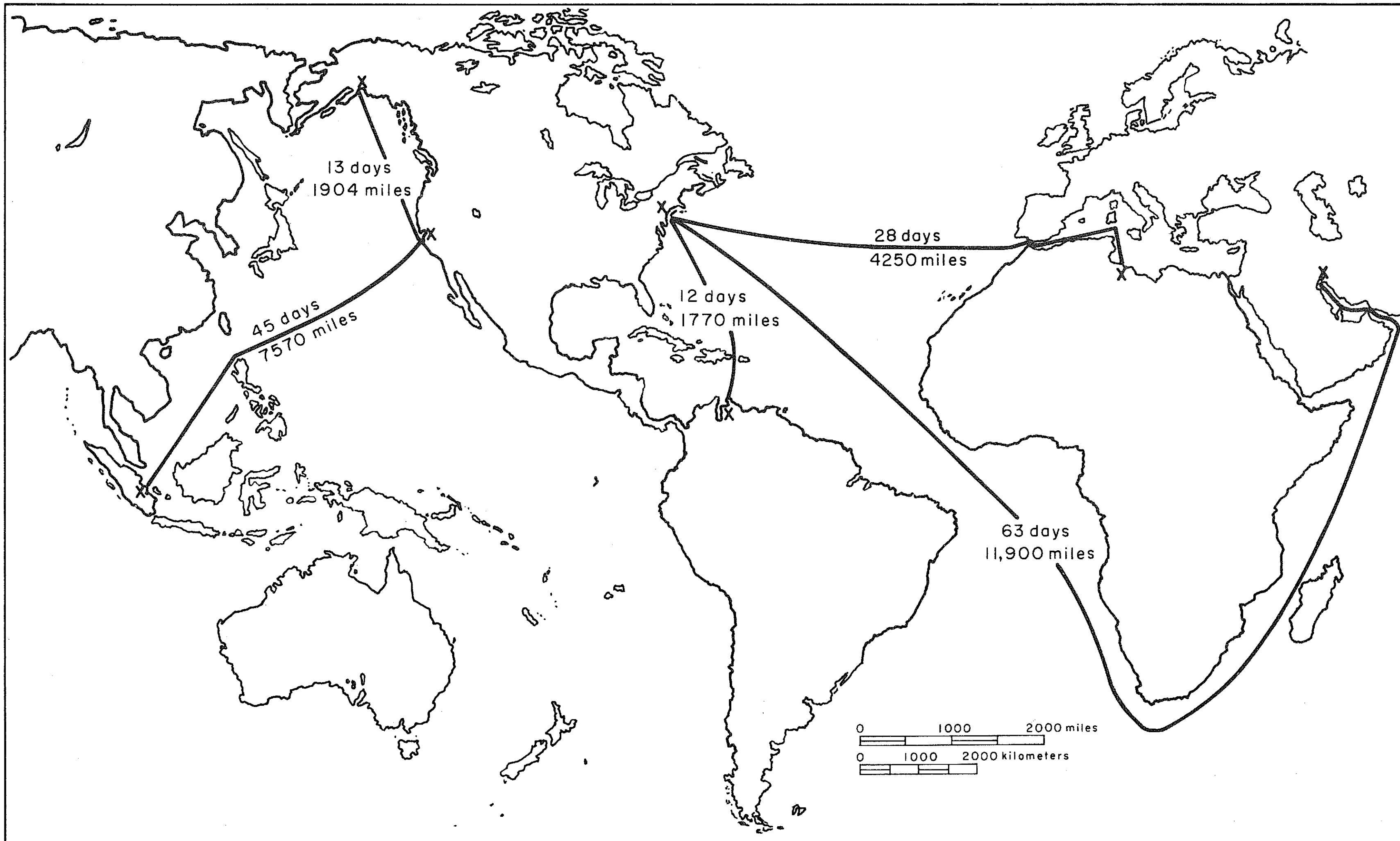


Fig. 13 - Transportation routes and shipping time for U.S. oil imports from Alaska, Indonesia, Venezuela, Libya, and the Persian Gulf.

of current world output and which is one of the areas with the greatest potential for increased production (Albers et al., 1973, p. 134-135; U. S. Bur. Mines, 1972a, p. 2-3).

Although production of oil in the African nations has grown significantly and is making important contributions to the current world petroleum supply, their reserves are equal to only 16 percent of those of the Persian Gulf area (Albers et al., 1973, p. 130-134; U. S. Bur. Mines, 1972a, p. 2-3). The increasing dependence of the major oil-importing nations on oil from the Persian Gulf area suggests numerous economic, political, and security implications (U. S. News and World Rept., 1973, p. 90-94).

Recently published reports indicate that industrialized nations throughout the world are seriously concerned about the adequacy of world supplies of petroleum and the potential problems of international competition for these supplies. A committee of the European Parliament recently issued a warning of a potential European energy crisis in Common Market countries by 1980 unless a comprehensive energy policy is developed, and it urged efforts to prevent a political struggle with the United States for available energy sources (Natl. Coal Assoc., 1973b). Because of fears of future fuel shortages, Japan is intensifying its worldwide exploration for oil, as well as purchasing additional reserves in the Middle East (Wall Street Jour., 1973b). The world's need for energy in the future will require that all potential sources be used to their fullest capacity.

The trend toward greater reliance on foreign oil sources by the United States not only carries the potential problems of balance of payments, international competition, and interruptions in supply, but it also makes that supply increasingly vulnerable in the event of hostile action at any time in the future. During the nearly 4 years of American participation in World War II, 95 U. S. tankers were sunk by submarine action along the East Coast, in the Gulf of Mexico, and in the Caribbean (Bachman, 1971). Figure 13 shows the distances from the various oil-producing areas to the United States. The ocean movement of much larger quantities of oil than those moved in the 1940s over distances that range up to more than 6 times as great as that from Venezuela to New York would make the protection of supply lines substantially more difficult than it was during World War II.

While imports of oil are vital to the United States as a whole, they are, in the short term, more critical to some areas of the nation than to others. In the event of an interruption in supply, the entire nation would suffer and, after a period of time, it might be that all regions would share the burden of the shortage equally. But initially, and until a system for the allocation and distribution of remaining sources could be developed, the blow would fall most heavily on those areas now most directly dependent on imported oil—the Atlantic and Pacific coastal regions. The coastal areas have been designated as Petroleum Administration for Defense (PAD) Districts I and V. In 1972, 67.3 percent of total oil imports went to District I, the East Coast, and 17.1 percent to District V, the West Coast (U. S. Bur. Mines, 1973b, p. 17-19).

Figure 14 shows percentages of crude oil and refined products used in Districts I and V that are provided by imports. Imports represented 47.8 percent of the total petroleum supply for District I in 1972, 35.9 percent of that for District V, and 29.0 percent of the total U. S. supply (U. S. Bur. Mines, 1973b, p. 32).

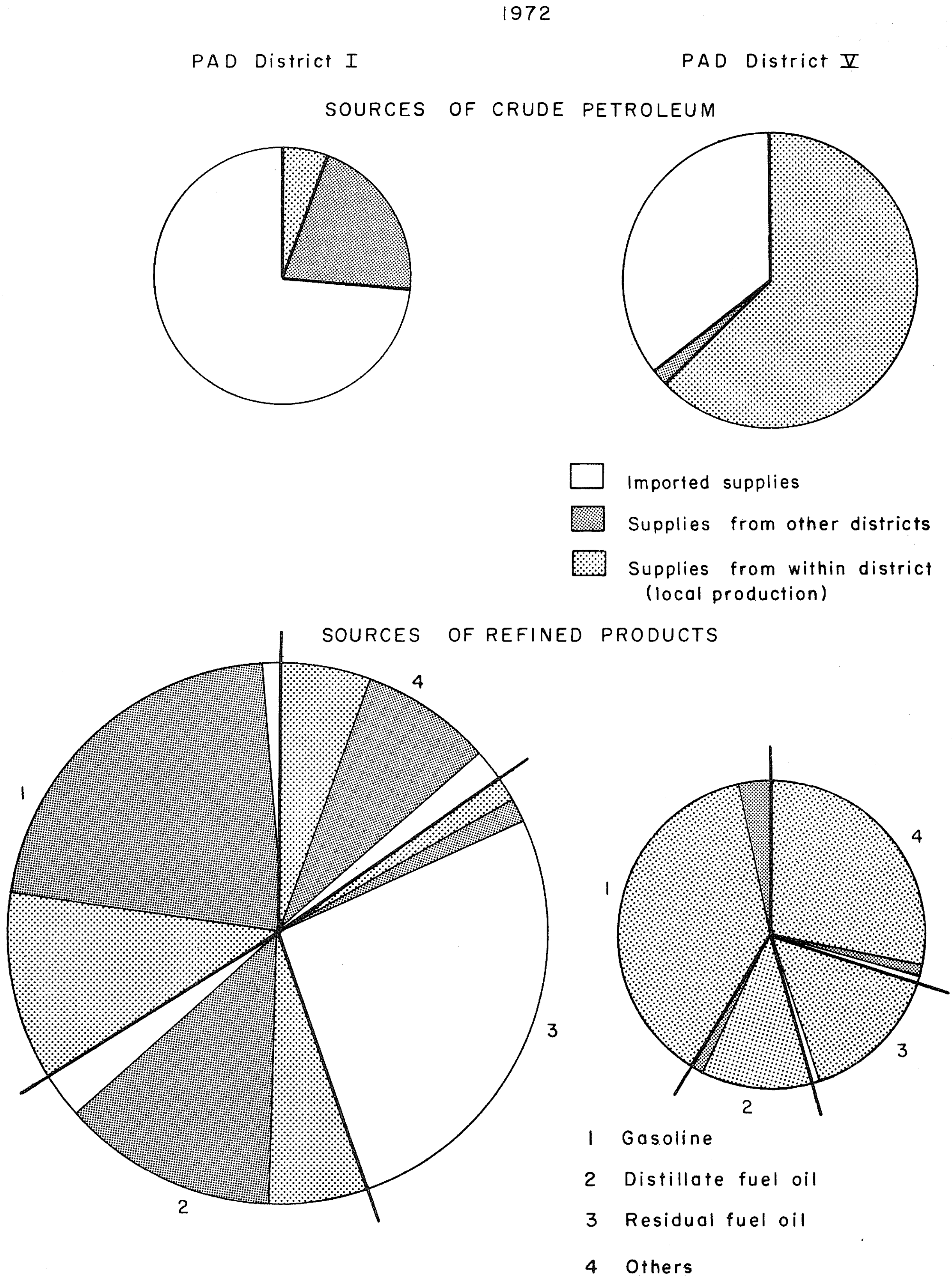


Fig. 14 - Sources of crude petroleum and refined products used in PAD Districts I and V in 1972. Size of circle is proportionate to quantities consumed.

Of the 1.1 billion barrels of crude petroleum and petroleum products imported to the East Coast in 1972, about 55.3 percent was residual fuel oil, used principally by electric utilities and heavy industry (U. S. Bur. Mines, 1973b, p. 17-19). Oil (mostly residual) provided 85 percent of the fuel energy consumed by electric utilities in the New England states and 40 percent of that used in the Middle Atlantic states in 1971 (Natl. Coal Assoc., 1972, p. 51-52).

LONG-TERM U. S. ENERGY POTENTIAL

The present shortage of available oil and gas and of productive capacity does not mean the energy resource potential of the United States is exhausted. Geologic evidence indicates that large undrilled areas, both onshore and offshore, are underlain by rocks favorable to the occurrence of oil and gas. Large additional quantities of these fuels are likely to be found if additional exploratory drilling is carried out in these areas. Huge tonnages of coal are already known to exist. Such coal can be burned directly to provide energy or it can be converted to liquid or gaseous form by processes that will at the same time remove the sulfur and provide a clean-burning fuel. Oil shales and tar sands with various degrees of oil saturation also are known to occur in extensive areas of the nation and to contain oil estimated at billions of barrels.

Besides the conventional fossil fuels—oil, gas, and coal—and other sources of energy, such as conventional nuclear, hydroelectric, and geothermal plants, that have contributed to our energy supplies in the past, other potential sources of energy, including oil extracted from oil shale and tar sands, advanced nuclear reactors, solar energy, and, on a smaller scale, wind and tidal power are likely to be used in the future. Each of these sources of energy has been enthusiastically discussed and promoted at one time or another as having the potential for making major contributions toward solving the energy problem. Undoubtedly each will eventually make some contribution, but none can realistically be considered as more than a partial solution to the energy dilemma. Major obstacles must be overcome in the development and use of each new source before its full potential can be realized. Man's initiative and ingenuity are capable of overcoming many of the physical limitations but not without the expenditure of large amounts of effort and capital and the passage of considerable periods of time. The relative potentials of various sources of energy and some of the problems that must be solved before their potentials are realized are discussed following.

Reserves, Resources, and Resource Base

Much misunderstanding exists regarding the use of the terms *reserves*, *resources*, and *resource base*. The term *proved reserves*, used in connection with oil and gas, is defined (Am. Gas Assoc. et al., 1972, p. 221) as "...the estimated quantity...which analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable from known oil or gas fields under existing economic and operating conditions." *Probable reserves* are defined as "...a realistic assessment of the reserves that will be recovered from all known oil or gas fields based on the estimated ultimate size and reservoir characteristics of such fields."

The term *reserves* has been used somewhat more loosely when applied to coal, oil shale, and some other minerals. It frequently has been used for identified or estimated deposits without qualifications regarding the economic recoverability of such deposits.

In contrast to the terms *reserves* or *probable reserves* applied to identified and economically recoverable deposits, the terms *resources* and *resource base* encompass deposits that remain as yet undiscovered and those portions of identified deposits that are not considered economically recoverable under current conditions.

Some people mistakenly consider proved reserves to be a measure of total future production, and, by dividing current production into proved reserves of a mineral, conclude that we will "run out in X number of years." That type of thinking fails to recognize that (1) new reserves are being steadily added through new discoveries; (2) continuing technological improvements and/or economic changes permit greater recovery of already identified deposits; and (3) the production from existing reserves, even if no new reserves were added, would not remain at a constant level and then end abruptly, but instead would continue during a long period of time at ever-declining annual rates.

McKelvey (1973, p. 12) has designed a diagram (fig. 15A) to distinguish the various categories of mineral reserves and resources. A U.S. Geological Survey modification of the diagram (Brobst and Pratt, 1973, p. 4) is shown in figure 15B. These diagrams should help to clarify some of the gradations in the levels of potential within the total resource base. The degree of certainty of existence of a particular mineral decreases in the diagrams from left to right. "Potential undiscovered deposits" can be shifted into the identified category only through exploration and/or accidental discovery. The vertical line between identified and undiscovered deposits would then be shifted to the right.

The horizontal line between recoverable and identified marginal deposits or conditional resources may be shifted downward either through (a) improved technology that makes greater physical recovery possible, or (b) favorable economic changes that lower production costs or raise the product value. The boundary between recoverable reserves and paramarginal or subeconomic resources will be raised by unfavorable economic changes. That is, recoverable reserves will be reduced in quantity.

For any given mineral, much of the existing resource base may never be discovered, and much of that actually identified may never be recovered because of technologic, economic, or political limitations.

Potential Future Energy Sources

To obtain some measure of the potential resource base of domestic energy from which the United States might ultimately draw, estimates have been made of the total amounts of the various fuels that originally existed in the ground. Such measurements generally are arrived at by estimating the areas and thicknesses of rocks favorable to particular mineral deposits and then estimating the likelihood that such deposits actually are or were present. By subtract-

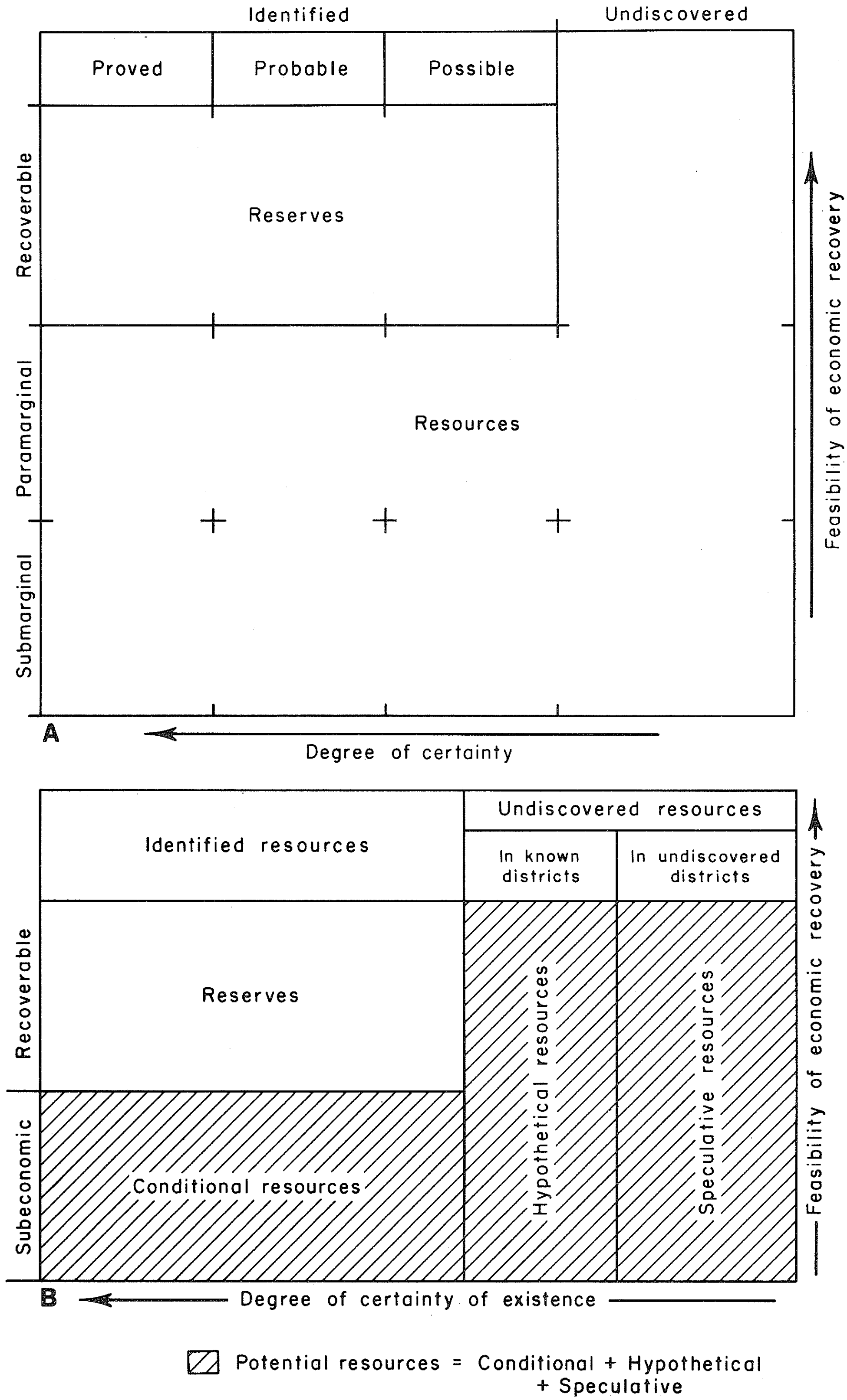


Fig. 15 - Classification of mineral reserves and resources. (Brobst and Pratt, 1973, p. 4, 12.)

ing past discoveries from the estimated original total, a potential undiscovered residual is computed. In some calculations, the amount likely to be recoverable rather than the total quantity in place is estimated.

Previous estimates of original oil and gas in place have varied widely, depending on when the estimates were made, the assumptions used, and the calculating procedures followed. Estimates of the original amounts of petroleum liquids and natural gas, as presented in a recent publication of the U. S. Geological Survey (Theobald et al., 1972, p. 13-18), are shown in table 1. The assumptions used in the various estimates are elaborated in that publication. For original natural gas in place, estimates are given in table 2.

The wide range of estimates shown in tables 1 and 2, in which the highest estimates are several times the lowest, indicates the uncertainty involved in estimating undiscovered deposits of oil and gas. The variations, reflecting primarily the speculative resources (fig. 15B), make the positions of the lower and right-hand borders of the diagram (fig. 15B) wholly tentative. The resource bases for some of the other fuels are less difficult to estimate than those for oil and gas.

Because sedimentary deposits of coal and oil shale generally occur in beds of relatively uniform thickness that extend laterally over wide areas, estimates of such resources can generally be made with a far greater degree of confidence than estimates of oil and natural gas, which are entrapped within the host rock under structural or stratigraphic conditions generally existing in much smaller and less regular areas.

Estimates of coal resources are based on areas thought to be underlain by coal and on estimates of average thickness of such coal seams. Actual existence of coal seams can be proved and average thickness measured in shafts or drillholes and at outcrops. Geologic data on the uniformity of thickness and lateral continuity of the individual seams permit a reasonably accurate extrapolation of the measured data into surrounding areas for considerable distances. Estimates of strippable coal reserves require additional detailed information on the thickness and nature of the overburden. If reserves are rated

TABLE 1—ESTIMATES OF TOTAL PETROLEUM LIQUIDS ORIGINALLY IN PLACE IN THE UNITED STATES

	Billion barrels		
Source of estimate	Conterminous U. S.	Alaska	Total
National Petroleum Council (1971)*	741.8*	82.6*	824.4*
U. S. Geological Survey (1972)	2,431.0	602.0	3,033.0
M. King Hubbert (1969)	575.0	85.0	660.0
L. G. Weeks (1958)	---	---	1,315.0
C. L. Moore (1970)	---	---	670.0
M. A. Elliott and H. R. Linden (1968)*	---	---	1,286.0*

* Crude oil only.

Source: Theobald et al. (1972, p. 13).

TABLE 2—ESTIMATES OF TOTAL NATURAL GAS ORIGINALLY IN PLACE IN THE UNITED STATES

Source of estimate	Trillion cubic feet		
	Conterminous U. S.	Alaska	Total
Potential Gas Committee (1971)	1,877	447	2,324
U. S. Geological Survey (1972)	5,690	1,380	7,070
M. King Hubbert (1969)	1,312	637	1,949
L. G. Weeks (1958)	---	---	1,250
C. L. Moore (1970)	---	---	1,934
M. A. Elliott and H. R. Linden (1968)	---	---	2,175

NOTE: Total discoveries, recoverable and nonrecoverable, through 1972, 872.5 trillion cubic feet (Am. Gas Assoc., 1973, p. 120).
Source: Theobald et al. (1972, p. 16).

according to quality or sulfur content, chemical analyses are made in addition to thickness measurements.

Oil shale estimates are generally based on estimates of the areas and measurements of the thickness of the deposits. Samples are also collected and tested to determine the potential yield of oil in 42-gallon barrels per ton of shale.

Estimates of conventional uranium resources are based on discovered deposits and on measured outcrops of favorable rock. Estimates of additional uranium resources are based on the quantities contained in uranium-bearing phosphate rock.

Although wide areas of the United States have been identified as having considerable geothermal energy potential, the amount of such potential that can confidently now be classified as recoverable resource is exceedingly small. Estimates of total potential must be largely inferred from general geologic knowledge and limited exploratory drilling.

Relative Abundance of Energy from Various Sources

The sources of energy considered to have the greatest immediate and long-term potential for supplying U. S. energy needs are shown in figure 16. Resource estimates used are from U. S. Geological Survey Circular 650 (Theobald et al., 1972). The area of the circle representing each source is proportional to the calculated energy content (in Btu) of the estimated resource base of each.

The conversion of the estimated physical quantities of the various energy sources into equivalent heat values (Btu), as shown in figure 16, is based on the conversion factors shown in table 3.

The scale at the lower left corner of figure 16 is applicable to all of the circles on the figure and provides a basis for comparison of the various sources. Comparison of actual numerical values is provided by table 4.

TABLE 3—FACTORS USED FOR THE CONVERSION OF FUEL UNITS TO Btu

Energy source	Conversion factor
Petroleum and natural gas liquids	5.6 million Btu/barrel
Natural gas	1032 Btu/cubic foot
Coal	25 million Btu/short ton
Shale oil	5.8 million Btu/barrel
Uranium	
Total contained energy	60 trillion Btu/short ton U_3O_8
Energy available with present technology	0.5 trillion Btu/short ton U_3O_8
Geothermal	4.0 Btu/1000 gram calories

TABLE 4—ESTIMATED POTENTIAL ENERGY CONTAINED IN VARIOUS RESOURCES

	Trillion Btu			
Source	Cumulative past production	Remaining identified	Identified recoverable	Potential undiscovered
Coal	880,000	39,750,000	9,750,000	81,640,000
Petroleum and natural gas liquids	593,000	1,876,000	263,200	14,515,200
Natural gas	403,900	476,420	300,000	6,415,900
Oil shale	Negligible	12,320,000	0[a] (3,360,000)[b]	14,660,000[c] (118,900,000)[d]
Geothermal	Undetermined	60,000	10,000	> 40,000,000
Uranium	Undetermined	22,500	12,500	800,000[e] (96,000,000)[f]
Hydroelectric	Undetermined	492,141[g]	224,270[h]	---

Source: Theobald et al., 1972.

[a] None currently economically recoverable.

[b] Containing 30 or more gallons of oil per ton.

[c] Based on extension of known resources.

[d] Undiscovered and unappraised.

[e] With present technology.

[f] Estimated total contained energy, assuming technology available to utilize it.

[g] Based on total estimated megawatt potential × load factor × energy factor × 50 years.

[h] Based on planned capacity by 1990 × average energy input × 50 years.

In figure 16A, estimates of cumulative production through 1970, of identified resources, and of the recoverable quantity of each fuel are shown. A large potential resource base is also indicated for each. As has been previously pointed out, some of the estimated potential base may not exist or, if in fact it does exist, may never be discovered or identified by techniques now available, and part of the resource that is ultimately discovered will be unrecoverable because of inadequate technology or the presence of economic conditions that make its recovery impractical. Despite the fact that the largest and most favorable estimates (those by the U. S. Geological Survey. See tables 1 and 2) have been used, the indicated potential for oil and natural gas is far lower than that for coal or oil shale (fig. 16A).

Of the identified deposits of oil, gas, and coal shown in figure 16A, a significant portion of each is in the economically recoverable category. Despite the large size of identified oil shale deposits, none has yet been proved economically recoverable.

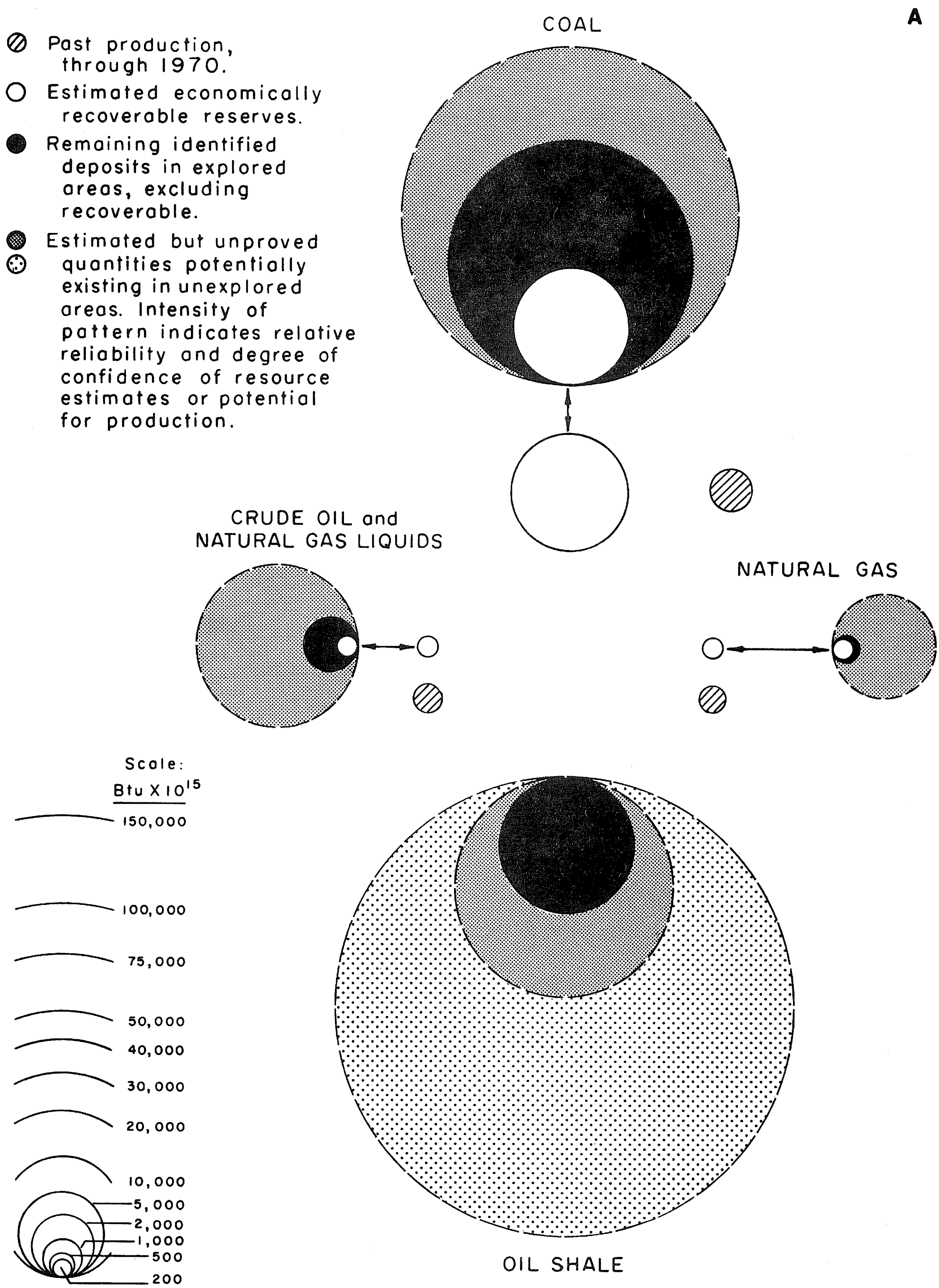
Comparison of the amounts of energy potentially recoverable from hydroelectric and solar power (fig. 16B) with those from fossil fuel sources is difficult because of the renewable or continuing nature of these resources. They involve a flow rather than a stock of energy. The total amount of solar energy reaching the earth's surface each year is enormous and far exceeds that potentially available from all other sources. However, because the amount of energy from this source that ultimately may be harnessed is completely undeterminable at this time, no attempt is made here to diagram it for comparison with other sources. Problems and potential connected with its use will be discussed later.

For converting hydroelectric power capacity to energy potential for inclusion in figure 16B, a power output extending over a 50-year average plant life, at the present average load factor, was assumed. The rate of reservoir siltation or plant obsolescence may reduce or extend the life of any individual plant, but the assumption of a 50-year average life should provide some measure of the relative magnitude of the energy this source can be expected to provide.

The amount of identified potential shown for hydroelectric power in figure 16B is based on the estimated total potential for hydroelectric power in the United States (U.S. Bur. Census, 1971. p. 503). The estimate of recoverable energy was based on the combined capacities of present hydroelectric plants and those planned for operation by 1990 (FPC, 1971, p. I-1-17).

The amount of uranium estimated to be economically recoverable (fig. 16B) is that identified in conventional deposits. The potential resources shown in the figure include the estimated potential for both undiscovered resources in conventional deposits and the estimated potential contained in uranium-bearing phosphate rock. The potential energy that would be recoverable from the estimated resources was calculated on the basis of present technology. Improvements in technology could greatly increase the amount of energy that ultimately could be recovered.

Although geothermal anomalies have been identified in a number of areas, there is as yet no way of determining how much of the geothermal potential may ultimately be realized.


A
Past production, through 1970.
Estimated economically recoverable reserves.
Remaining identified deposits in explored areas, excluding recoverable.
Estimated but unproved quantities potentially existing in unexplored areas. Intensity of pattern indicates relative reliability and degree of confidence of resource estimates or potential for production.
COAL
CRUDE OIL and NATURAL GAS LIQUIDS
NATURAL GAS
OIL SHALE
Scale:
Btu X 10^15
150,000
100,000
75,000
50,000
40,000
30,000
20,000
10,000
5,000
2,000
1,000
500
200

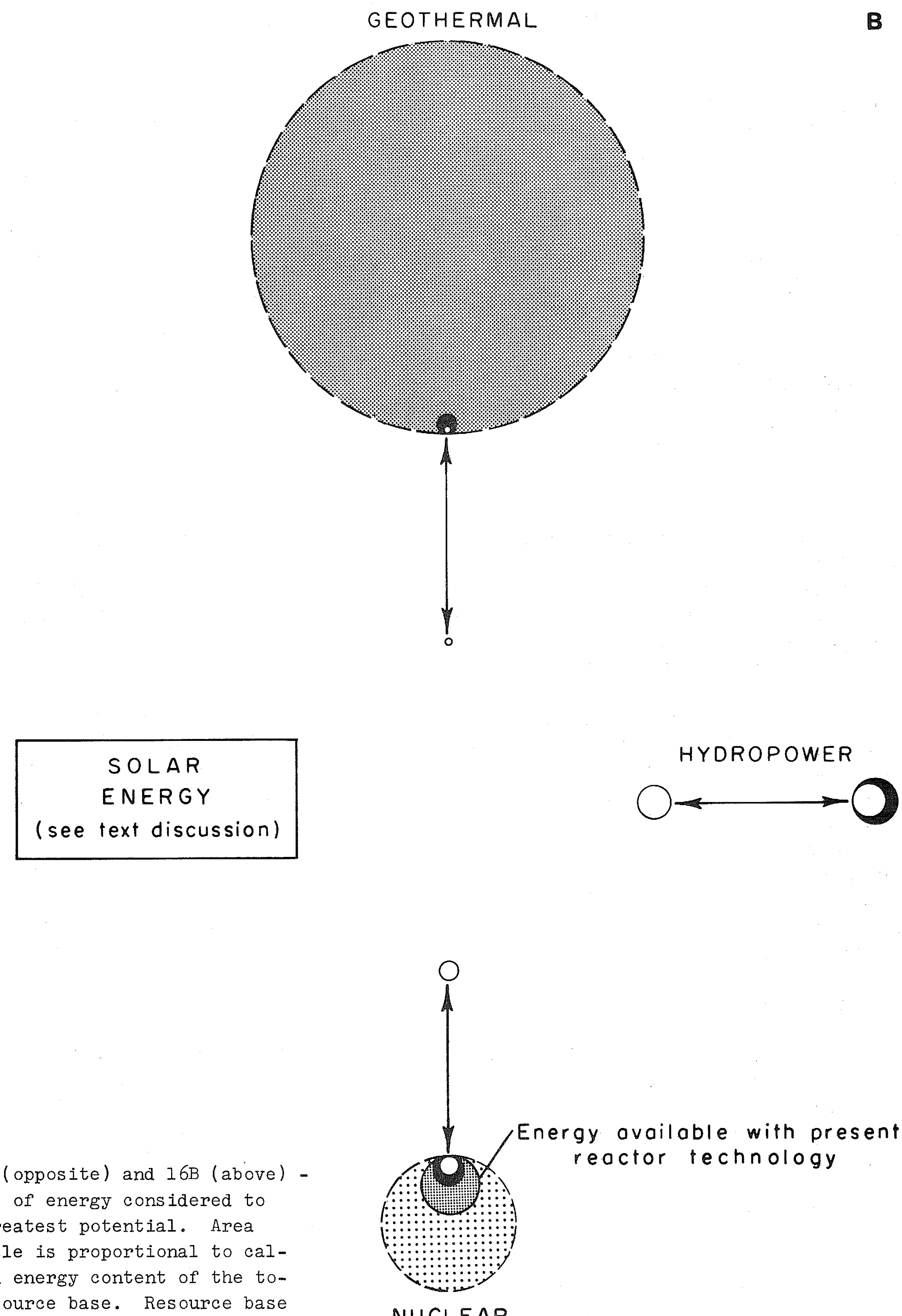


Fig. 16A (opposite) and 16B (above) - Sources of energy considered to have greatest potential. Area of circle is proportional to calculated energy content of the total resource base. Resource base estimates are from Theobald et al. (1972). Conversion to Btu is based on factors shown in table 3.

ACHIEVING POTENTIAL ENERGY LEVELS

The United States can continue to meet a major share of its future energy requirements by accelerating research and development of the various alternative sources of energy. In addition to intensified exploration for domestic natural gas and petroleum supplies, work is needed on gasification and liquefaction of coal, the extraction and processing of shale oil, the development of processes and equipment for controlling the undesirable combustion products of coal, the perfection of the breeder and fusion reactors, and the utilization of solar, geothermal, tidal, and other unconventional types of energy wherever possible and to the fullest feasible extent.

The immediate and full use of each of the alternative sources of energy is currently being prevented in some degree by problems, existing either singly or in combination, that involve the resource itself or technology, economics, or the environment.

Petroleum and Natural Gas

Earlier sections of this report have described how the production of liquid fuels and natural gas has risen steadily through recent decades to levels where remaining proved reserves can no longer sustain a continued growth. In fact, if increases in producible reserves are not added without delay, production of both petroleum and natural gas will soon begin to decline rather than resume the former upward trend.

Geologic data indicate that rocks favorable to the occurrence of large deposits of oil lie beneath as yet unexplored land and offshore areas of the United States. However, until they are actually discovered and developed through drilling, such deposits remain only potential supplies and cannot help to alleviate our immediate shortages. Recent increases in prices for both oil and gas should stimulate the rate of exploration and, hopefully, of new discoveries. But new discoveries do not automatically make large producible supplies immediately available. After an initial discovery, a period of 4 to 7 years is normally required before the potential of a new territory can be developed and brought into full production. For this reason, even though there should be an immediate increase in the rate of drilling there will be a time lag before producing capacity can be significantly increased.

A further problem is related to establishment of a reserve-to-production ratio that will maintain increased productive capability. Once the limit of producibility has been reached, a relatively stable level of production can be maintained only if the amount of reserves withdrawn each year is replaced by an equal amount of new reserves. To increase production and maintain that new higher level of production indefinitely, however, requires additions to reserves that are several times the amount of the increase in withdrawal (fig. 17).

For example, when operations are at full capacity, the withdrawal of one unit of natural gas from the recoverable reserves requires the replacement of an equivalent unit in the recoverable reserves category. However, because only about 80 percent of the discovered gas can be recovered, the discovery or identification of 1¼ units of gas in place are required to provide the single replacement unit.

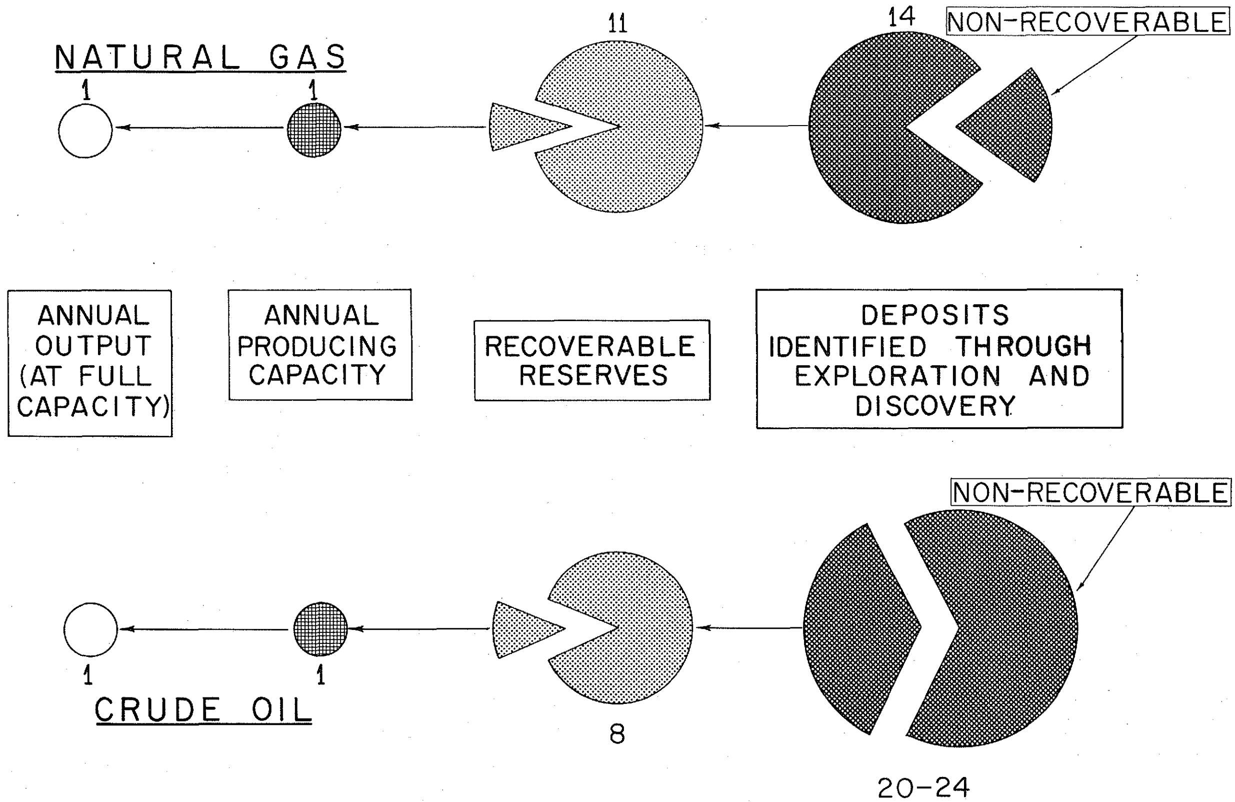


Fig. 17 - Reserves of natural gas and crude oil vs. productive capacity. Numbers are units required to provide one unit of productive capacity. After initial discovery, 4 to 7 years are normally required to reach full production.

If, on the other hand, it is assumed that an increase of one unit of annual output is required and that this increased level of production is to be maintained indefinitely, not one but approximately 11 units of new recoverable reserves must be added, and that would require the discovery or identification of about 14 units.

In oil production, where an R/P ratio of about eight is required, the addition of eight units of recoverable reserves would be needed to maintain the one-unit increase in production (fig. 17). However, because present technology recovers only 35 to 40 percent of the oil, identification of about 20 to 24 units of oil in the ground would be required to sustain production at a higher than present level.

If economic means were to become available for recovering oil that is currently identified but not recoverable, the effect would be an immediate large increase in proved reserves and a complete shift in the relationships shown in figure 17. This could come about through new technology or a sufficiently big price increase to make some present tertiary recovery methods economic.

The foregoing examples, while they admittedly are greatly oversimplified, illustrate one aspect of the energy dilemma confronting the United States.

Adequacy of Resource Base

Natural Gas

Discoveries of recoverable natural gas (including those of the Alaskan North Slope) through 1972 were estimated at 702 trillion cubic feet (Theobald et al., 1972, p. 16; Am. Gas Assoc. et al., 1973, p. 120). Cumulative production through that year amounted to 436 trillion cubic feet, leaving an estimated recoverable reserve of 266 trillion cubic feet at the end of 1972.

Projections (Dupree and West, 1972, p. 17) indicate an increase in the use of natural gas from the 1972 level of 22.9 trillion cubic feet to about 26.2 trillion in 1980, 27.5 in 1985, and 33.0 trillion in the year 2000. These projections assume additional gas will become available to meet the anticipated demand. To provide such levels of production would require, beginning in 1973, cumulative new additions to recoverable reserves amounting to 369 trillion cubic feet by 1985 and to 881 trillion cubic feet by 2000.

Combining these new additions with the 436 trillion cubic feet produced prior to 1973, the total cumulative discovery requirements for production and supporting reserves would be about 800 trillion cubic feet by 1985 and 1300 trillion cubic feet by 2000. Most of the estimates of original gas in place shown in table 2 indicate that, even with only 80 percent recovery, sufficient natural gas may exist to meet the demand to the year 2000. But existence merely provides the potential. To serve the nation's growing energy needs, natural gas must, first, be found at a rate to match the growth in need, and, second, be produced at a cost low enough to make its production economically feasible.

Crude Oil and Natural Gas Liquids

Cumulative production of petroleum and natural gas liquids through 1972 is estimated to have been about 114 billion barrels (Theobald et al., 1972, p. 13; Am. Gas Assoc. et al., 1973, p. 24, 122). Estimates of the amounts of liquid fuel originally in place in the ground vary widely (table 1), as do the estimates of the amounts that will ultimately be recoverable, which range from 231 billion barrels to 617 billion barrels (Theobald et al., 1972, p. 13). After deduction of the pre-1973 production of 114 billion barrels, the estimated remaining quantities would range from 117 billion to 503 billion, of which 43 billion barrels is currently classified as proved reserves.

Projections of U. S. consumption of liquid fuels indicate an increase from the 6 billion barrels per year in 1972 to 9.1 billion barrels in 1985 and to 13 billion barrels in 2000 (Dupree and West, 1972, p. 17). To meet such demands, cumulative production beginning in 1973 would total 95 billion barrels by 1985 and 260 billion barrels by 2000. Under the least optimistic estimates of the potentially recoverable reserves, a severe decline from even the present level of domestic production would occur long before the end of the century. The most optimistic estimate of potentially recoverable liquids is 243 billion barrels more than the total cumulative consumption indicated. It is also more than 60 times the 1972 production.

Whatever the actual quantities of natural gas and petroleum liquids existing beneath United States territory, a large potential does remain, and the immediate problem of the availability of domestic oil lies not in lack of resource base but in other factors.

Accessibility of Potential Petroleum and Natural Gas

Some of the most promising areas included in the estimates of potentially existing deposits of petroleum and natural gas in the United States are not now, or have not been in the past, accessible for exploration and drilling. Among the most significant of these areas is the Outer Continental Shelf (OCS), which is under Federal control and available for exploration only by lease from the Federal Government. Leasing began in 1953, and by 1972 approximately 4.3 million acres were under lease for mineral exploration and production (U. S. Geol. Survey, 1972, p. 15). Additional areas will become available for exploration through lease sales held from time to time by the Federal Government. In recent years such sales have been held with increasing frequency.

In 1972 about 12 percent of the U. S. oil and natural gas liquids production and about 13 percent of natural gas production came from the OCS areas (U. S. Geol. Survey, 1972, p. 75). Most of the OCS production to date has been in the Gulf of Mexico, off the coasts of Louisiana and Texas. The gain in annual production of liquid fuel from the OCS from 1968 to 1972 was approximately equal to the gain in total U. S. output during that period. From this it may be inferred that without the OCS contribution growth in total output would have leveled off 4 years ago. A leveling-off of OCS production in 1972 is a further indication of the need to make new offshore areas available for exploration, if the national output of oil and gas is to be maintained. However, delays have been encountered in opening up these areas.

A lease sale involving OCS tracts in the Gulf of Mexico was delayed by legal action from December 1971 until September 1972 until environmental impact statements satisfactory to the court could be provided. Leasing in the California offshore area has been halted since the blowout that occurred in the Santa Barbara Channel on January 28, 1969. Production from some of the existing wells in the area of the blowout also has been halted. On the eastern seaboard, strong opposition has been voiced to exploratory drilling off the coast because of fear of possible environmental effects of drilling and production activities. As a result, that area is currently being withheld from leasing.

Access to some already proved reserves has been restricted. Producible reserves of gas amounting to 26 trillion cubic feet (approximately 10 percent of our total known reserves) and 10 billion barrels of oil (about 23 percent of the known recoverable liquid fuel supplies) have been identified in the Prudhoe Bay area on the North Slope of Alaska but are currently unavailable because of a lack of transport facilities. Construction of the planned trans-Alaska pipeline has been delayed by environmental litigation. The Alaskan crude oil reserves thus affected are exceeded only by the reserves of Texas (12.14 billion barrels) and are greater than the combined proved crude oil reserves of 28 of the 30 states (other than Alaska) producing oil in 1972. Only Texas and Louisiana have greater natural gas reserves than those currently shut-in in Alaska. These unavailable Alaskan gas reserves are equal to the combined proved reserves of 27 of the 33 states (other than Alaska) that produced gas in 1972.

Other much smaller identified and producible oil deposits, such as those held in naval petroleum reserves for national defense purposes, also are unavailable for production.

Physical, Technologic, Economic, and Time Factors

Even if, as the estimates of the existing resource base indicate, sufficient oil and gas resources should exist in this country to meet the needs of the United States for all or most of the years remaining of the Twentieth Century and perhaps beyond, interrelated problems remain to be overcome before the potential can be realized. Overcoming each of these difficulties will require time.

Merely to maintain 1972 levels of production, the rate of new additions to recoverable reserves of natural gas must exceed by about 27 percent the average of annual additions from 1956 through 1970 in the lower 48 states, and annual additions to reserves of crude oil and natural gas liquids must be 20 percent above the 1956-1970 average. To provide for growth in demand for these fuels, still greater increases in the rate of new discoveries must be achieved. In recent years the amount of oil and gas found per foot of hole drilled has decreased significantly (Natl. Petroleum Council, 1971, p. 38). As a result, achieving an increase in the rate of new discoveries is likely to require a higher rate of drilling than would have been necessary in the past when success ratios were higher and when more of the oil and gas discovered came from shallower deposits.

The effectiveness of any extensive effort designed to bring about a major increase in the rate of discovery and production of oil and gas in the United States could be greatly enhanced by expanded research and improved technology. Increased geologic research, more precise tools for exploration, improved recovery techniques, and greater speed and lower cost of drilling probably would contribute most to expansion of production capacity. None of these fields has been neglected—indeed, all have received much attention, and progress has been made. Further improvement, however, could have significant impact.

In the past two decades large quantities of previously nonrecoverable oil have been produced through secondary recovery and pressure maintenance procedures. Additional quantities will be gained through tertiary recovery procedures currently being applied, primarily on an experimental and research basis. Research on stimulation of production of natural gas from "tight" geologic formations by fracturing the rock with atomic explosives to permit the freer flow and increased recovery of gas is being studied.

The percentage of oil being recovered from any given deposit has been increasing gradually. Estimated cumulative recovery efficiency rose from 25.21 percent of total oil discovered through 1955 to 30.28 percent in 1969, and it is expected to reach 37.03 percent in 1984 (Natl. Petroleum Council, 1971, p. 34).

In geophysical exploration much progress has been made in the identification of geologic structures favorable to the accumulation of oil and gas. However, whether or not oil or natural gas deposits actually exist can be determined only by drilling. As the major structures are discovered and tested, the search must increasingly turn to more subtle structural features, stratigraphic traps, and other geologic features that may escape detection by techniques now available. Deposits occurring in such features are, in general, likely to be less prolific producers than previously found fields in more favorable structures. Successful research on better techniques to identify these areas will increase chances of discovering the reserves needed in the future.

Assuming that adequate incentive exists to encourage an intensified exploration effort, there is still a physical limit to the amount of exploration that can be accomplished within a given period of time. The limit is determined largely by the number of drilling rigs that are available and the rate at which the drilling can be done. Considerable progress has been made in increasing drilling speed and lowering drilling costs. These and further improvements can not only speed up the rate of exploration and development of sites but also make economic some of the sites that previously did not warrant such development.

The balance between costs for exploration, development, and production on the one hand and prices of the oil or gas on the other influences not only the decision as to whether exploration should be undertaken but also the decision as to whether a deposit can be economically produced after it is discovered. Although more exploration can be anticipated as prices increase and the prospects for an adequate return on investment improve, there is, nevertheless, a limit to the rate at which production can be expanded after new discoveries are made. Even under the most favorable conditions, the availability of capital and equipment are limited. There is also a limit to the rate at which plans for new offshore lease sales can be made and carried out and to the rate at which capital can be accumulated by industry for participation in these sales.

If additional domestically produced oil is to help meet the increasing demand for petroleum products, rather than merely replace part of the crude oil now being imported, then additional refinery capacity also will be needed. This, too, will require time and large capital investments.

It appears that domestic oil and gas resources and production potential are such that, with favorable economic conditions, the output of oil and gas can be increased and the domestic situation improved. However, in light of the tasks involved, the magnitude of the effort required, and the lag times that can be reduced to only a limited degree, it seems unrealistic to anticipate any very significant change in the domestic oil and gas supply situation by 1980 or any major improvement before 1985.

Coal

Domestic deposits of coal originally in place in the United States that have thus far been identified by exploration and mapping have been estimated to contain almost 1600 billion tons of coal of various grades, thicknesses, and depths. Areas not yet explored and mapped are estimated to contain additional coal amounting to more than 1600 billion tons (Theobald et al., 1972, p. 3).

TABLE 5—ESTIMATED TOTAL TONNAGES OF REMAINING COAL RESOURCES BY TYPE AND REGION, JANUARY 1967

Region	Total identified resources (billion tons)	Percent			
		Anthracite and semi-anthracite	Bituminous	Sub-bituminous	Lignite
Appalachian	270.57	4.6	95.4	--	--
Interior	278.41	0.2	97.2	--	2.6
Northern Rocky Mts.	315.76	--	2.2	34.5	63.3
Southern Rocky Mts., West Coast, and Alaska	695.12	--	40.3	59.6	0.1
	1,559.86				

Source: Compiled from Averitt, 1969, p. 12.

TABLE 6—ESTIMATED SULFUR CONTENT OF REMAINING COAL RESOURCES OF THE UNITED STATES*

Region	Sulfur ranges:—	Percentage of deposits in each sulfur range			
		0.7 or less	0.8 - 1.0	1.1 - 1.5	> 1.5
BITUMINOUS COAL					
Appalachian		14.4	17.2	15.4	53.0
Interior		0.1	0.3	2.7	96.9
Northern Rocky Mts.		42.0	45.7	1.4	10.9
Southern Rocky Mts., West Coast, and Alaska		48.4	47.2	--	4.4
SUBBITUMINOUS					
80 percent in Rocky Mts.; remainder in Alaska		66.0	33.6	0.1	0.3
LIGNITE					
96 percent in N. Dakota and Montana		77.0	13.7	9.2	0.1
ANTHRACITE					
93 percent in Pennsylvania		96.5	0.6	--	2.9

* Modified from Federal Power Commission, 1971, p. I-4-9.

By the end of 1970 about 36 billion tons of coal had been mined and consumed; assuming an average estimated mining recovery of 50 percent, an approximately equal amount of coal has been rendered nonrecoverable in the process of past mining. Of the remaining identified coal, about 390 billion tons are considered minable with current technology. Of those, an estimated 200 billion tons are believed to be recoverable at costs approximating those prevailing today, whereas the remainder will involve higher costs. The estimated 390 billion tons is almost 11 times the 36 billion tons already produced and approximately 650 times the 1972 production. In energy content, it is equivalent to more than 1600 billion barrels of oil, or 9000 trillion cubic feet of natural gas. If the coal were actually processed into liquid or gaseous form, however, the energy of the new fuels would be only about 80 percent of the initial energy of the coal used, because energy would be lost during conversion.

Adequacy of Resource Base

Although the identified and minable coal deposits represent total resources many times current annual requirements, these deposits are not uniform in size, thickness, minability, chemical make-up, heat content, and geographic distribution. Rarely are all these characteristics at their most desirable level in a single deposit; more often there is a combination of desirable and undesirable. As a result, even though the total resources of coal are huge, those deposits that are able to meet certain specifications tend to be limited in both quantity and quality. For example, the bituminous coal deposits lying near the juncture of Kentucky, Virginia, and West Virginia have an almost unique combination of coking characteristics, low-sulfur and low-ash contents, and desirable levels of volatile matter that make them highly valued as coking coal throughout the world. But, because of their low-sulfur and low-ash contents and their high heat content, these coals (especially the higher volatile types) are also now being sought for power generation and other uses at a time when mines in other areas that are producing higher sulfur coal are being shut down because their coal cannot meet air-quality standards.

Figure 18 shows the location of coal deposits, by type, throughout the United States, and figure 19 gives the typical chemical make-up and average heat contents of the various grades of coal.

Table 5 shows the estimated total resources of coal in four regions of the nation and the percentages represented by each grade. Bituminous coals, which have high heat contents (fig. 19), predominate in the eastern part of the nation, while subbituminous coals and lignites, which have lower heat values, predominate in the western part. Table 6 gives estimated percentages of the total coal resources in each region that fall within various ranges of sulfur content. No separate data on the sulfur contents of those coals classified as economically recoverable have been tabulated, and we can only assume that the sulfur contents of these coals would have a distribution similar to those given in table 6. It is apparent from the table that larger quantities of low-sulfur coal exist in the western areas, but most of those coals also have a low-Btu content.

If the percentage of sulfur in a coal is to be used as a criterion of its suitability, the available reserves acceptable for use are greatly reduced.

Regulations have limited to 1 percent or less, by weight, the sulfur content of coal burned in a number of major metropolitan areas. While large quantities of western coal can meet this limit, essentially none of the coal in the Interior Coal Provinces and only an estimated 31.6 percent of the coal of the Appalachian region can meet this standard.

The western coal deposits have long been pointed to as a source of almost unlimited quantities of low-sulfur coal. However, much of even that coal cannot meet recently established air-quality standards based on sulfur dioxide (SO_2) emissions per million Btu of heat input. Federal Environmental Protection Agency regulations applicable to all major new fuel-burning plants (constructed or modified after August 1971) limit SO_2 emission to 1.2 pounds of SO_2 per million Btu of input. Primary air-quality standards aimed at protection of public health have been established across the nation, but the states are now faced with a Federal requirement that secondary air-quality standards, for the protection of property, be placed in effect by June 30, 1975. President Nixon in his Energy Message of April 18, 1973, in effect warned the states against the premature and widespread application of unnecessarily stringent secondary standards because of the lack of adequate low-sulfur fuel supplies and sulfur control technology to meet such standards (Science, 1973).

If all the sulfur contained in the coal is assumed to pass into the combustion gases, an assumption that may not be absolutely true but is essentially so, almost no coal containing 1 percent sulfur could, in its natural state, meet the 1.2-pound emission standard. A heat value of 16,666 Btu per pound would be required before coal with as much as 1 percent sulfur could be

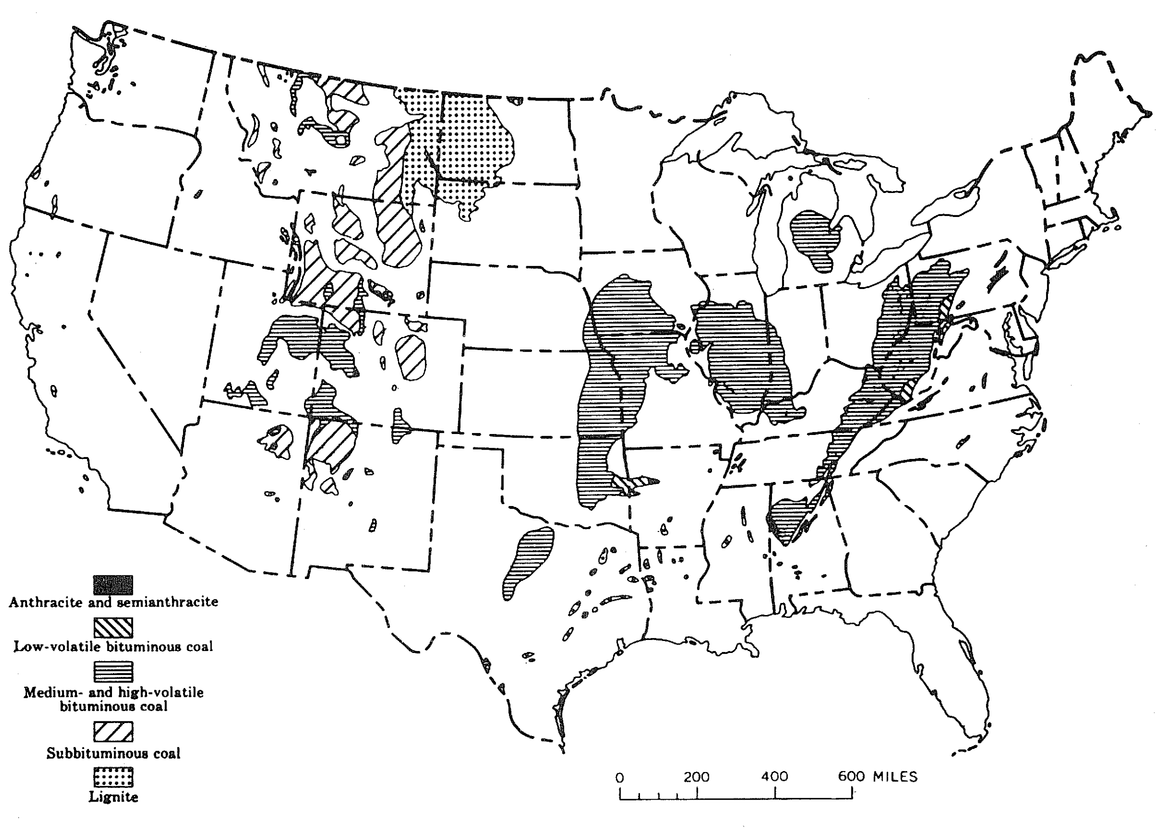


Fig. 18 - Coal fields of the conterminous United States (from Averitt, 1969).

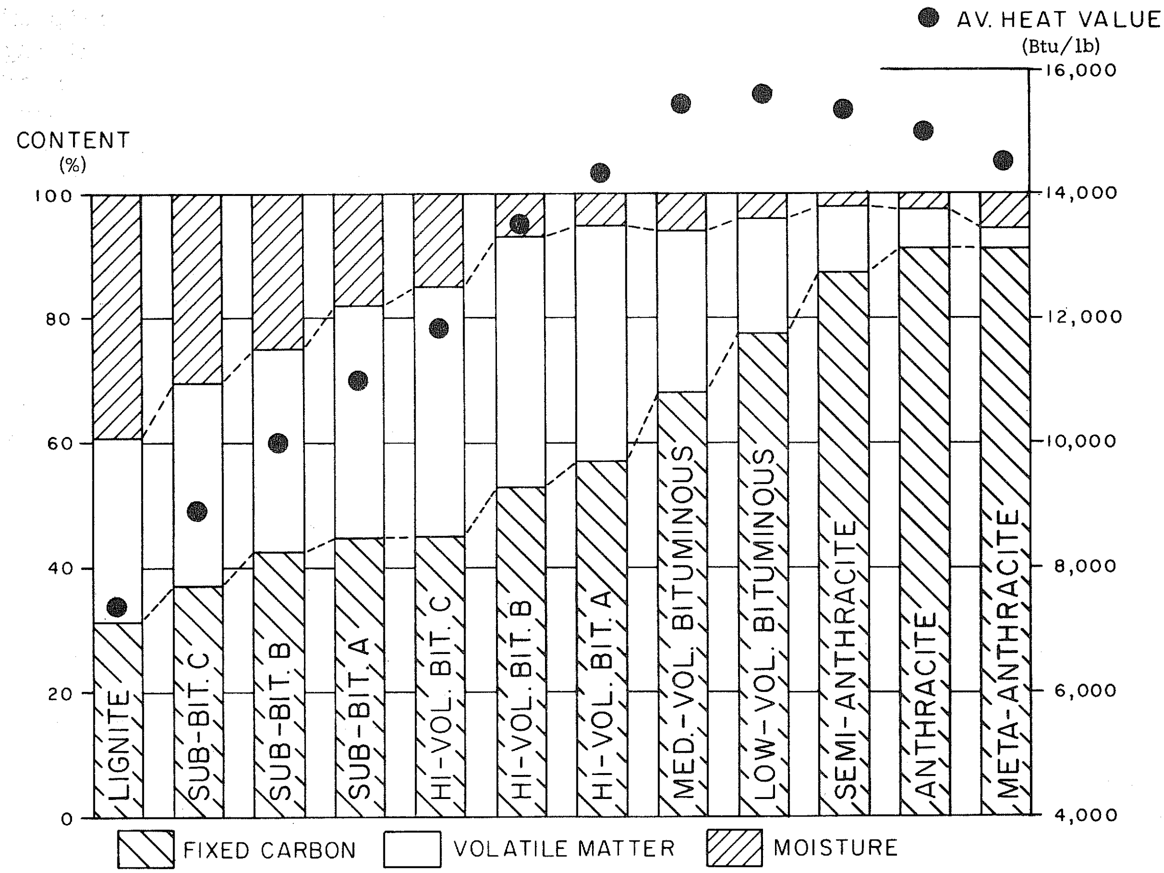


Fig. 19 - Variations in the chemical content of United States coal on an ash-free basis (from Averitt, 1969, p. 16).

burned. An average bituminous coal of 12,000 Btu per pound could have no more than 0.72 percent sulfur, and a lignite with a heat value of 7000 Btu per pound would be limited to a 0.42 percent sulfur content. Even with treatment by standard coal cleaning processes essentially none of the coal in the Interior Provinces, an area that currently provides about 25 percent of the nation's coal output, can be considered a fuel resource for newly constructed utility plants, and a major part of the Appalachian deposits would also be unacceptable.

What portion of the low-sulfur coal of the West could meet the standards for new plants on the 1.2 pounds of SO_2 per million Btu basis, or could be made acceptable through beneficiation, has not yet been determined. Some insight may be gained by examination of the data assembled in a study made of potential sites for major electric power installations in the Northern Great Plains area (North Central Power Study, 1971, p. 35). Forty-two potential sites were identified, for 40 of which the ranges of sulfur content and heat content and the estimated tonnages of recoverable coal reserves were given. The 40 sites contained an estimated 44.7 billion tons of coal, but in 16 of them, with 25 percent of the tonnage, the coal was calculated to exceed the 1.2 sulfur dioxide limit, even when the highest heat content and lowest sulfur content were used. If averages of the reported sulfur contents and Btu values are used, the coals at 28 sites, containing 74 percent of the reserve tonnage, exceed the 1.2-pound per million Btu sulfur limit. It is likely that the coal from some of the sites could be upgraded sufficiently by cleaning to meet the standard, but much of it is so far above the limit that current standard cleaning processes are likely to be inadequate.

In most of the states east of the Mississippi River, ownership of coal deposits is in private hands, and purchase or lease of coal for mining is negotiated directly between buyer and seller. However, in the West much of the coal is located on Federal lands and leased to applicants under provisions of Federal statutes. New leasing of coal lands is currently being restricted to operators needing additional acreage for continuation of existing operations or reserves for production planned for the near future (Mining Record, 1973a, p. 2).

Environmental Problems in Production

Coal, both in its natural form and in the gaseous and liquid forms that are expected to become available in the future, is capable of supplying much of the nation's future energy needs. But important environmental problems associated with its production must first be solved.

Major environmental problems associated with coal mining are the effects of strip mining, subsidence, and acid mine water. Considerable research is being done on each of these problems, but much more is needed. Proposals have been made to ban surface mining completely. While such action would undeniably eliminate environmental impact in new areas, it would also eliminate millions of tons of production annually (approximately 50 percent of all coal mined), much of which goes into electric power generation, at a time when no other source of fuel is available. Further research is needed to improve methods of stabilizing spoil banks after the coal has been removed, of controlling sediment run-off from the disturbed land into adjacent waters, and of reestablishing vegetation on the mined-out land. Some terrains require more complex procedures and efforts for control than others; for example, spoil banks left by contour mining in mountainous terrain are more difficult to stabilize and control than those formed during areal strip mining in country that is relatively flat, and the reestablishment of vegetation in the arid regions of the West is proving to be much more difficult than is true for areas that have greater rainfall.

Surface subsidence above underground mines is likely to become an increasingly severe problem with the passage of time because it often occurs long after production has ceased and the mine has been abandoned. The likelihood of severe subsidence increases with the thickness of the coal seams and with moderate rather than greater depths. Pumping fill material into the abandoned mine workings to support the overlying strata appears to offer some promise in controlling subsidence. Leaving larger support pillars when coal is removed is another solution, but it has the disadvantage of abandoning large amounts of coal. The more complete removal of the coal, with planned and controlled surface subsidence, has had considerable success in other countries.

Utilization Problems and Possible Solutions

The greatest threat to the continued use of coal as an energy source has stemmed from concern over the environmental effects of the emission of particulate matter and sulfur dioxide during coal combustion. Particulate matter emissions can be largely controlled by the use of currently available electrostatic precipitators. The control of sulfur dioxide emissions, however, is a much more complex problem.

Most of the means that hold the greatest long-term promise for future control of sulfur dioxide are not yet well enough developed to offer solutions to the problem in the near future. Among the possible solutions currently under investigation are (1) use of low-sulfur coal, (2) flue-gas desulfurization, (3) coal cleaning, (4) coal refining, and (5) coal conversion.

Use of Low-Sulfur Coal

The availability of and limitations on low-sulfur coal resources were discussed earlier. Fuel restrictions imposed on existing power plants located in areas where new air-quality standards have already been imposed have led to an increased demand for low-sulfur coal from the West and from eastern low-sulfur coal regions. Demand by utility plants and other coal consumers for coal that formerly was used primarily for coking and was considered too expensive for utility use has pushed prices for these coals, f.o.b. the mine, to levels twice those of a few years ago. Because most midwestern coals cannot meet the current sulfur standards, about 7 million tons of Wyoming coal per year, hauled approximately 1200 miles from mine to utility plants, is being burned in the Chicago area. Although coal prices at the mine tend to be relatively low in the Western states, the greater transportation costs result in delivered fuel costs at midwestern utility plants that are twice those of coal available near the plants. Announcements have been made of plans to ship Wyoming coal to eastern Texas, Oklahoma, Kansas, and other equally distant places because suitable alternative fuels are not available locally.

Ironically, the inability of a large share of our most abundant fuel to meet the standards that have been set has tended to intensify some of our other energy problems. For example, the amount of railroad diesel fuel required to haul the 7 million tons of coal from Wyoming to Chicago is about 750,000 barrels per year, equivalent to about 3 to 5 percent of the heat value of the coal being transported. But this one operation has increased the annual U. S. consumption of railroad diesel fuel by 0.87 percent at the very time when nearly all the increases in petroleum supply are coming from foreigh sources. The other long distance shipments of coal from the Rocky Mountains to the Southwest and Midwest that have been announced will further intensify the problem.

Because of the transportation costs involved in the use of western coals, utilities farther east that have been unable to obtain low-sulfur coal from nearer sources are reported to be considering other alternatives. Plans have been reported to import low-sulfur coal from Poland for use by eastern power plants. Shipping costs are projected to be only $4.00 to $4.50 per ton— far less than shipping western coal by rail to the same point (Skillings Mining Rev., 1973).

Flue-Gas Desulfurization

With standards based on sulfur dioxide emissions per million Btu, rather than on the sulfur content of the fuel itself, the use of higher sulfur coal could be continued or even increased if a technologically and economically feasible process can be devised for removal of sulfur oxides from the combustion gases.

Numerous conflicting statements have been issued regarding the availability or nonavailability of proved techniques and equipment for removal of sulfur gases. Consequently, the public is highly confused about the reality of the situation. Some manufacturers advertise widely that they have proved equipment available. Some electric utilities have spent large sums for research and for installations of desulfurization devices, only to discard them later because they failed to perform adequately.

A committee of the National Academy of Engineering (NAE), after a comprehensive study of the processes and equipment available, reported in 1970, "...contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist" (Natl. Acad. Engineering—Natl. Research Council, 1970, p. 3). Three years after the NAE/NRC report, great uncertainty still appears to remain as to whether a workable technique has actually been proved.

In the decision of April 19, 1973, the Court of Common Pleas of Lawrence County, Pennsylvania, ruled that the Pennsylvania Power Company could not be punished for not complying with state sulfur emission standards because lack of commercially available sulfur-removal equipment made compliance impossible. The court stated (Natl. Coal Assoc., 1973a):

> ...the present state of technology relative to control of SO_2 emission by the use of devices or processes for removal from flue gases remains theoretical....
>
> No device is commercially available today, as distinguished from technique or theory, with an adequate degree of reliability to solve the problems of SO_2 removal.

Investigating teams have recently inspected installations in Japan and report successful sulfur control operations have been achieved under the conditions and regulations existing there. Questions have been raised as to whether these devices are applicable under the conditions existing in the United States and whether the resulting waste materials from the process could be disposed of in an economic and acceptable manner under the environmental regulations that are in effect in the United States (Lundberg, 1973).

A recent study made by the Battelle Memorial Institute indicated that it is unlikely that most U. S. coal-burning utility plants can depend on sulfur dioxide removal technology to meet the proposed 1975 deadlines for compliance with sulfur emission regulations. It further stated that a demonstrated level of efficient sulfur dioxide recovery with 90 percent reliability during a full year of operation on any full-sized, coal-fired unit probably will not occur in the United States before 1975 (Oil and Gas Jour., 1973c).

An interagency committee within the Federal Government established to assess the potential for sulfur oxide removal systems for steam electric power plants has expressed the belief that, with an additional 18 months of operating experience, the engineering barriers to successfully applying stack-gas cleaning devices should be overcome. The study group, known as the Sulfur Oxide Control Technology Assessment Panel (SOCTAP), included personnel from the Environmental Protection Agency, the Office of Science and Technology, the Department of Commerce, and the Federal Power Commission (SOCTAP, 1973, p. 2).

The majority of the panel members forecast that by the end of 1975 about 10,000 megawatts of generating capacity should be equipped with sulfur scrubbing systems, and by the end of 1977 the capacity so equipped should have increased to between 48,000 and 80,000 megawatts. They estimated that by 1980 75 percent of the coal-fired generating capacity should be equipped, which would allow the use of 400 million tons of high-sulfur coal annually. The Federal Power Commission task force members and other reviewers were more pessimistic.

Obviously, despite continuing efforts for several years, there is still no complete agreement on the availability of proved techniques. Even when a device is perfected, it will take years to install it in all plants that now burn high-sulfur coal. Flue-gas desulfurization, therefore, offers no immediate solution to the sulfur dioxide problem.

Coal Cleaning

Sulfur occurs in coal as particles of iron sulfide (pyrite) and as organic sulfur intimately tied up with the chemical structure of the coal itself. Cleaning by gravity techniques utilizes the difference in the specific gravities of the pyrite and the coal to separate the two. Another process for cleaning coal is froth flotation. Both methods have been used for many years with varying degrees of success. Successful separation depends on the initial freeing of the discrete particles of pyrite from the coal. If the particles are finely disseminated throughout the coal, conventional cleaning methods have limited success in reducing sulfur levels. Typically, about half the sulfur in the coal is in the form of pyrite, half of which might be removed by normal cleaning procedures. However, this means that 75 percent of the total sulfur content is still left in the coal unless other means of removal are employed.

Tests on 322 samples of coal (Deurbrouck, 1972) from various mines showed that the sulfur distribution in these coals varies widely between regions and even between coals within a given region, as does the potential for removing the sulfur by a combination of crushing and cleaning the coal. In less than 30 percent of the samples could the sulfur content be reduced to 1 percent, and most of those samples were initially low in sulfur. Although significant reductions in total sulfur in coals from the Midwest could be achieved, the sulfur content in relatively few of them could be reduced to a 1 percent level because the percentages of organic sulfur and remaining pyritic sulfur would still be too high (Deurbrouck, 1972, p. 18).

Coal Refining

Because of the limitations of reducing the sulfur in coal by physical means, especially in those coals with a high organic sulfur content, chemical processes for "cleaning" coal are under investigation. One such process, solvent refining, has progressed to the point where a pilot plant is now under construction in Washington state. In solvent refining, pulverized coal is dissolved in a coal-derived solvent, and most of the sulfur and other impurities are removed by filtering. The remaining solvent-refined product can be burned as a liquid or cooled to form a solid fuel that has a heat content of about 16,000 Btu per pound. The process is reported to be capable of removing all of the pyritic sulfur and more than 60 percent of the organic sulfur. In small-scale experiments, a Kentucky coal containing 3.6 percent sulfur yielded a refined product containing only 0.7 percent sulfur (Atkinson, 1973). A product with a heat value of 16,000 Btu per pound that contains only 0.7 percent sulfur would form only about 0.9 pound of sulfur dioxide per million Btu during combustion and would easily meet the air pollution control standards. By-products of solvent refining include light liquids and sulfur. The cost of the solvent-refined coal has been estimated by the developers of the process at about 60 cents per million Btu. When the pilot plant now under construction has been operated long enough to prove the technologic and economic feasibility of the process, solvent refining may permit the continued and expanded use of high-sulfur coal by converting it to a fuel that can meet environmental standards. Other chemical methods of sulfur removal from coal also are being studied.

Coal Conversion

Another way of enabling high-sulfur coals to help meet the energy needs in areas where their use is now banned or being curtailed is the conversion of the coals to low-sulfur or sulfur-free liquid fuel or gas.

Gas manufactured from coal was used in many metropolitan areas long before natural gas became available to them, but such gas had a low heat content. With the increase in availability of natural gas, which has a high heat content (about 1000 Btu per cubic foot), the manufacture of low-Btu gas made from coal was discontinued in most locations. Liquid fuel, too, has been produced from coal; in fact, much of Germany's liquid fuel supply during World War II (Reed, 1948, p. 36) was derived from this source.

Research on coal conversion has been under way in the United States for many years. As early as the 1940s an extensive research program had already been started by the Federal Government (Fieldner et al., 1944), and by the late 1940s extensive research on coal hydrogenation and gas synthesis was under way at demonstration plants in Louisiana, Missouri. A pamphlet, issued at the time of the dedication of the demonstration plants, carried the following statements (U.S. Bur. Mines, 1949, p. 24):

> In the Coal-to-Oil Demonstration Plants of the Bureau of Mines, cooperating closely with industry, engineers and scientists are preparing today for tomorrow's era of synthetic liquid fuels, an era that will dawn much sooner than once was anticipated....
>
> The ultimate necessity for producting synthetic fuels is well-understood...the only question is "When?" If we learn by experience, the answer is "Now" to those who recall the desperation under which the synthetic-rubber industry was developed during World War II....

Results of this research indicated that conversion was technically feasible but not economically competitive at that time. The plants were closed in June 1953 (U. S. Bur. Mines, 1956, p. 162).

In the early 1960s there was a resurgence of interest in coal conversion, and a number of research projects were undertaken or expanded. This research has continued, and several processes are under study, some of which have reached the pilot-plant stage. Descriptions and discussions of these processes have appeared frequently in magazines and other publications in recent years

(Office of Coal Research, 1973, p. 19-36; U. S. Bur. Mines, 1972b, p. 33-34; Chem. Eng. Progress, 1973; Oil and Gas Jour., 1967a; Oil and Gas Jour., 1967b; Business Week, 1968; Layng and Hellwig, 1969; Linden, 1966).

To provide a trillion cubic feet of synthetic gas per year, less than 5 percent of the 1972 annual consumption of natural gas in the United States, would require the output of 11 plants with a capacity of 250 million cubic feet per day. Allowing for maintenance and other down-time, 12 plants would likely be required to assure such a supply. The estimated investment required for 12 such plants would be about 3 billion dollars, with perhaps another one-half billion dollars or more for mines to supply the approximately 75 million tons of coal per year required to feed the plants. Such coal production would be equivalent to the combined output of the 18 largest mines operating in the United States in 1972 (Coal Age, 1973). Their output, if from underground mines, would require from 12,000 to 20,000 miners, depending on seam thickness and mining conditions.

During a 20-year plant life, each gasification plant would require more than 125 million tons of coal. Assuming 50 percent recovery for underground mining, a deposit containing a total of 250 million tons of coal in the ground would be required to provide the needed 125 million tons; strip mining, with about 80 percent recovery, would require about 160 million tons of coal in the ground. To provide 125 million tons of coal by underground mining (with 50 percent recovery) would require about 35,000 acres of coal if the coal seam averaged 4 feet thick. In 6-foot coal the required acreage would be reduced to about 23,000 acres (Risser, 1968, p. 20). If surface mining were used, the acreages would be reduced by about 37.5 percent.

The water requirements for coal gasification plants are enormous. For once-through cooling, about 1 billion gallons would be required every 24 hours to supply the needs of a plant producing 250 million cubic feet of gas per day (NAE/NRC, 1972, p. 50). Oddly enough, very little mention of water requirements has been included in most published descriptions of the various gasification processes, despite the large amounts of water needed and the fact that the large deposits of Western coal—a prime source of coal for gasification—commonly lie in areas where water supplies are limited. A significant portion of the required water is consumed in the processes.

Most efforts at coal gasification are aimed at producing gas of pipeline quality that is composed primarily of methane and has a heat value of about 1000 Btu per cubic foot. However, power generating installations and certain other consumers can use a lower Btu, low-sulfur gas manufactured by other processes. Low-Btu gas, sometimes referred to as "power gas," has a heat value of about 150 Btu per cubic foot. Such gas must be used at or near the point of production, because of the high cost per unit of energy that is involved in its transmission for any appreciable distance.

The processes for production of low-Btu gas, consisting primarily of partial combustion of coal with air and steam, are much simpler than those for gas of pipeline quality. The resulting gas is made up largely of hydrogen, carbon monoxide, and nitrogen, with smaller amounts of carbon dioxide and methane. Because of its low heat value, large quantities of the gas would be needed to provide the energy required by electric power generating units. The efficiency of using low-Btu gas would be increased significantly by using it in a combined cycle in which the hot gas is first used to drive a gas turbine and then exhausted through a boiler to produce steam (Metz, 1973, p. 54).

One of the processes for making low-Btu gas that is currently receiving considerable attention is the Lurgi process. This method uses partial coal combustion with oxygen and steam to produce a gas with approximately 21 percent carbon monoxide, 28 percent carbon dioxide, 40 percent hydrogen, 10 percent methane, and 1 percent other gases. After the carbon dioxide has been removed, the gas has a heat value of about 450 Btu per cubic foot (NAE/NRC, 1972, p. 25-26). With proper adjustment of combustion units, such gas might be blended in limited percentages with high-Btu natural gas to produce a fuel with a relatively slight reduction in the heat content of the mixture. Lurgi gasification plants are currently operating in several foreign countries. Considerable publicity has been given to plans to construct Lurgi gasification plants in northwestern New Mexico, but none has as yet been built.

In addition to proposed development of separate gasification or liquefaction processes and plants, the development of large coal processing complexes in which multiple coal-based products would be produced jointly has been suggested. In such plants each ton of coal might provide one barrel of oil, about one-fourth of a ton of solvent-refined coal, 4000 cubic feet of high-Btu gas, a small quantity of by-product chemicals, and almost 350 kilowatt hours of electricity (U. S. Dept. Interior, 1972, p. 3).

Despite the many research efforts, none of the liquefaction processes is as yet beyond the pilot-plant stage, nor have any of the processes for making high-Btu gas of pipeline quality advanced beyond pilot-plant research. The economic production of gas and liquid fuel from coal on a large scale would not only serve to make greater use of coal—the nation's largest fossil fuel resource—but also would supplement the declining domestic supplies of natural gas and crude petroleum.

In 1972 a panel of the Committee on Air Quality Management of the National Academy of Engineering—National Research Council examined several processes designed for production of gas of pipeline quality (NAE/NRC, 1972) and weighed their advantages and disadvantages, stages of development, and problems remaining to be solved. The four processes considered most advanced were selected, and programs were outlined to develop these processes up to the point at which demonstration plants would be needed to further evaluate the processes. The panel defined a demonstration plant as "...a single processing train of commercial size with the necessary purification, methanation, and other facilities to produce pipeline-quality synthetic gas. The plant should operate satisfactorily for one year" (NAE/NRC, 1972, p. 7).

The panel's schedule and estimated cost for a developmental program on coal gasification is shown in table 7. A thorough study and evaluation of the processes on a pilot scale will determine whether any one is outstanding or whether a combination of parts of several processes should be used.

The proposed schedule, if adhered to, would provide, by the end of 1975, the data on which a decision can be based as to whether a demonstration plant would be justified (NAE/NRC, 1972, p. 41). The final design and construction would take perhaps 2 to 4 years, after which the recommended 1 year of satisfactory operation would follow. Obviously, the optimistic predictions of a

TABLE 7—PROPOSED SCHEDULE AND ESTIMATED COSTS FOR DEVELOPMENTAL PROGRAM ON COAL GASIFICATION†
(millions of dollars)

	1972	1973	1974	1975	TOTAL
Institute of Gas Technology Hy-Gas processes: 1. Steam-oxygen 2. Electrothermal* 3. Steam-iron*	11	12	10	7	40
	Construction	Operation		Decision	
Bureau of Mines Synthane process	7	7	5	5	24
	Construction	Operation		Decision	
Bituminous Coal Research, Inc. Bi-Gas process	7	7	5	5	24
	Construction	Operation		Decision	
Consolidation Coal Company, Inc. Acceptor process	7	5	5	3	20
	Construction	Operation		Decision	
Process evaluation, selection, and design	1	1	2	2 Selection	6
	Process Evaluation and Preliminary Design				
Basic research and development	2	2	2	2	8
	Continuing activity				
TOTAL	35	34	29	24	122

* Processes not considered promising by panel.
† As proposed by ad hoc Panel on Evaluation of Coal-Gasification Technology.
Source: NAE/NRC, 1972, p. 42.

viable coal gasification industry capable of providing significant quantities of pipeline-quality gas before 1980 appear very unlikely. Not before the early 1980s can the first commercial gasification of coal be expected, and the development of a large gasification capability will require even more time.

Hydroelectric Power

The best hydroelectric sites, from the standpoint of potential reservoir size and geographic location in relation to present and projected power demands, have already been developed. Recent proposals for development of additional sites have, almost without exception, encountered resistance because of the alleged detrimental impact on the environment that could occur.

Conventional hydroelectric plants under construction and those proposed for completion by 1980 will provide 16,000 megawatts of additional hydro-

TABLE 8—FORECAST OF U.S. NUCLEAR POWER CAPACITY, 1971-1988

Fiscal year	Gigawatts† High Additions	Cumulated	Most likely Additions	Cumulated	Low Additions	Cumulated
1971	--	7.0	--	7.0	--	7.0
1972	8.7	15.7	5.2	12.2	2.2	9.2
1973	15.9	31.7	11.9	24.1	9.8	19.0
1974	18.6	50.2	18.1	42.2	13.8	32.8
1975	11.2	61.4	12.3	54.5	14.0	46.8
1976	8.3	69.7	5.2	59.7	9.8	56.6
1977	14.7	84.4	16.6	76.4	10.1	66.6
1978	20.0	104.4	21.1	97.4	16.1	82.7
1979	21.9	126.3	19.2	116.6	18.2	100.9
1980	25.6	151.9	22.4	139.0	20.5	121.4
1981	27.3	179.2	23.7	162.8	21.4	142.9
1982	29.0	208.2	25.2	188.0	22.7	165.6
1983	34.0	242.2	29.6	217.6	26.6	192.2
1984	38.0	280.2	33.0	250.6	29.7	221.9
1985	41.3	321.4	35.9	286.4	32.3	254.2
1986	45.2	366.6	39.3	325.8	35.4	289.6
1987	48.9	415.5	42.5	368.2	38.2	327.8
1988	55.4	471.0	48.3	416.6	43.5	371.3

† 1 gigawatt = 1000 megawatts = 1,000,000 kilowatts.
Source: U.S. Atomic Energy Commission, 1971b, p. 5.

TABLE 9—PROJECTIONS OF THE GROWTH IN NUCLEAR GENERATING CAPACITY, 1962-1972

(A)

Year of projection	Projected year-end capacity (thousand megawatts) 1970	1975	1980	1985
1962	5	16	40	--
1964	6	29	75	--
1966	10	40	95	--
1967	10	61	145	255
1969	6	62	149	277
1970	5	59	150	299
1971	--	--	151	306
1972	--	--	132	280

(B)

Actual year-end capacity (thousand megawatts) 1969	1970	1971	1972
4.3	7.5	10.0	14.7

Sources: 1962-1970 data: U.S. Atomic Energy Commission, 1971a, p. 8; 1971-1972 data: Mining Record, 1973b, p. 2.

electric capacity, an increase of 30.8 percent above that of 1970. By 1990 the anticipated increase will be 30,000 megawatts of additional capacity, 57.7 percent above the 1970 level. Such increases will represent only 4.6 percent of the total projected electric power capacity (all types of plants) increases through 1980 and 3.0 percent of those through 1990 (Federal Power Comm., 1971, p. I-1-17).

Nuclear Energy

Nuclear energy at present appears to offer the best promise for adequate supplies of energy for the long-term future. The U.S. Atomic Energy Commission (1971b, p. 5) projected the pattern of growth through 1988 shown in table 8. The difficulty in accurately projecting the growth of nuclear energy is shown by the earlier projections of the level of capacity that might be anticipated up to 1985 (table 9).

During the middle to late 1960s, the growth of the nuclear power industry exceeded earlier expectations, and projections were revised upward. By the early 1970s, however, construction began to lag and estimates were revised downward. At the end of 1972, the 1971 estimate for 1980 capacity was revised downward from 151,000 megawatts to 132,000 megawatts, a reduction of about 12.6 percent. The projection for 1985 was lowered to 280,000 megawatts from an earlier projection of 306,000 megawatts, a reduction of about 8.5 percent. The projection for year 2000 is 1,200,000 megawatts (Mining Record, 1973b). The downward revisions were the result of numerous delays caused by public opposition based on concern about plant safety and potential environmental effects and by delays in construction and fabrication of plants and units.

The magnitude of the projected developments in nuclear power can be appreciated when one considers that the 35,900 megawatts projected for construction in 1985 (table 8) is the equivalent of placing one major new 1000-megawatt nuclear generating unit into operation every 10 days for a year. The projected increase from 280,000 megawatts in 1985 (table 9A) to 1,200,000 megawatts in 2000 will require placing the equivalent of one new 1000-megawatt unit into service every 6 days for 15 years.

Adequacy of Resource Base

Identified uranium resources in conventional deposits, recoverable at $8.00 per pound of uranium oxide (U_3O_8), are estimated at 250,000 short tons. Identified submarginal resources that are recoverable at up to $15.00 per pound are estimated at 200,000 tons. Potential undiscovered resources in known uranium districts, which are recoverable at between $8.00 and $15.00 per pound, are estimated at twice those already identified (Theobald et al., 1972, p. 23). Other undiscovered uranium resources are thought likely to be found in districts not now identified as uranium districts. Additional quantities of uranium that are present in phosphate rock may become economically recoverable as by-product material from phosphate mining and processing operations if and when uranium prices reach a sufficiently high level.

If breeder reactors can be developed and put into operation in significant numbers by the last half of the 1980s, uranium fuel supplies should be adequate for future needs. Should an operative, economic breeder reactor fail to materialize by that time, however, severe problems may arise from a scarcity of low-cost supplies (Electrical World, 1970, p. 27). Cumulative U.S. requirements for uranium oxide from 1971 through 1985 have been projected at 450,000 tons, with 59,300 tons needed during 1985 alone (Natl. Petroleum Council, 1971, p. 147). Before 1990, total cumulative requirements will exceed the current estimate of our low-cost uranium resources.

Added to the long-term concern over adequate uranium supplies is the more immediate problem of whether the uranium-enrichment capacity will be adequate to convert the natural uranium into fuel at a rate sufficient to meet the growing demand. According to one prediction, three times the current capacity will be needed by 1985 to meet demands (Chem. Marketing Reporter, 1972, p. 7). Only when the breeder reactor has become a reality and is in full-scale operation will the concern for adequate supplies of fuel to support continued growth of the nuclear industry be allayed.

Environmental Problems

Permanent disposal of the radioactive waste that will be produced in ever-increasing quantities as nuclear power production expands also is a problem, and no satisfactory solution has yet been found. Proposals made thus far have encountered strong opposition.

In addition to the physical and technological problems normal to a developing industry, nuclear energy production has also had to contend with public concern aroused by fear of health hazards and of damage to the environment. Widespread debate over safety standards and potential environmental damage has led to numerous delays, and some of the questions still remain to be resolved (Gillette, 1972a,b,c,d,e).

Future Role in Total Energy Picture

Nuclear power is expected to provide the equivalent of 11,750 trillion Btu of energy to the U.S. economy in 1985 and 49,230 trillion in 2000. This is equivalent to 10.1 percent of the projected total consumption of total gross energy inputs of 116,630 trillion Btu for 1985 and 25.7 percent of the 191,900 trillion Btu total projected for 2000 (Dupree and West, 1972, p. 21). Total U. S. energy consumption in 1972 was estimated at 72,091 trillion Btu (U.S. Bur. Mines, 1973a, p. 1).

The 11,750 trillion Btu of nuclear energy projected for 1985 is equivalent to 2.1 billion barrels of oil, 11.4 trillion cubic feet of natural gas, or 470 million tons of coal. The 49,230 trillion Btu for 2000 is equivalent to 8.8 billion barrels of oil, 47.7 trillion cubic feet of natural gas, or 1969 million tons of coal. (See table 3 for conversion factors.) If the projections for total energy consumption are approximately correct, a shortfall of even 10 percent in nuclear output would result in huge increases in the need for other forms of energy.

Geothermal Energy

Geothermal energy has been proposed as a "...cheap, clean, accessible fuel that can be easily harnessed to generate vast quantities of electricity" (Business Week, 1973, p. 74). Preliminary information available at this time indicates that a large potential does indeed exist. About 1.8 million acres in the United States have been designated as known geothermal resource areas, and another 95.7 million acres are considered to have potential for providing geothermal energy (Chasteen, 1972, p. 101).

About 90 percent of the known potential for geothermal energy in the United States lies in 13 western states and Alaska, much of it on Federal lands where it has, thus far, been inaccessible for development (Chasteen, 1972, p. 101). The competitive auctioning of leases for tracts of Federal lands, permitted under the Geothermal Steam Act of 1970, is expected to make some of these areas available, perhaps in 1973.

Despite the widespread and optimistic publicity given this potential source of energy, the technological and other problems that remain to be solved probably will retard its extensive use in the near future.

The geothermal wells at The Geysers north of San Francisco in California produce noncorrosive dry steam, which is ideal for use in low-pressure turbines such as are used at that site. However, most other geothermal fields discovered thus far within the United States produce mineral-laden hot brines that are extremely corrosive to pipes and equipment. In addition to a corrosion problem, hot brines present a potential disposal problem, for they can pollute the ground and surface waters if they are not handled carefully. Experimental units now under development hopefully will prove capable of dealing with the corrosion, disposal, and associated problems presented by these brines (Business Week, 1973, p. 75).

Geothermal energy may be used either directly as a source of space heat or to generate electricity. Geothermal steam has been used to heat homes in Iceland since 1925 (Lear, 1970, p. 56). For space heating the energy must be used at or very near the source. Electricity from geothermal energy must be generated at or near the source but can be transmitted by high-voltage lines to more distant locations for ultimate use.

To be economically competitive, geothermal energy delivered to a given market must be less expensive than energy obtainable from other sources, including fossil fuels that may be readily transported to almost any point where they are needed. Geothermal energy can be expected to play its greatest role in areas where concentrations of population and industry occur in close proximity to geothermal fields, and/or where existing transmission lines pass near the geothermal field.

It has been estimated that in less than 20 years geothermal energy will meet 5 percent of California's total power requirements. This means an output of between 6 and 9 million kilowatts (Wilson, 1973, p. 70). Total geothermal capacity in California is expected to be approximately 3000 megawatts by 1981, about 1986 from The Geysers and 1010 from the Imperial Valley and other areas.

Geothermal energy may ultimately play an important role in helping to meet local and regional energy needs. However, no very significant contribution towards solution of the over-all energy problem can be anticipated from this source, even in the West, for more than a decade at best.

Oil Shale

The amount of oil shale estimated to exist in the United States is enormous (fig. 16). Not all of this shale, however, is as rich as the thick shales of Utah, Colorado, and Wyoming, which contain 30 gallons or more of oil per ton. The estimated shale resources also include thinner beds in the Middle West, Southwest, and elsewhere that contain no more than 10 gallons per ton. Although these lower grade shales might some day provide a source of liquid fuel and thus must be considered part of the total resource base, the actual economic development and use of such low-grade resources lies far in the future. At today's oil prices even the high-grade deposits cannot produce oil at competitive prices, but it has been estimated that if oil prices increase to 4 to 5 dollars per barrel, 80 billion barrels of oil might be economically recoverable from shales containing 30 gallons or more per ton.

By far the bulk of the rich oil shales of the West is on Federal lands, and access to at least some of these deposits will be necessary before a significant oil shale industry can develop. In July 1971, after a 41-year period in which no oil shale lands were leased, the Department of the Interior announced its intention of offering six tracts for competitive bidding in December 1972. The six tracts, representing test (or prototype) leases, were to be selected from sites nominated by interested firms (Oil and Gas Jour., 1971). Nominations of 23 sites were received, and six of them were to be selected for bidding after environmental impact studies and examinations were completed and evaluated (Mining Record, 1972).

In June 1973, the solicitation of bids on the six sites, originally scheduled for December 1972, was still awaiting completion of environmental impact statements. The statements were being expanded to meet objections by various groups who had held that the initial statements were inadequate (Mining Record, 1973c).

Considerable research has been done on the retorting of shale to produce liquid fuel, and demonstration plants with capacities ranging from 150 to 1000 tons of shale per day have been constructed and operated (Dinneen and Cook, 1972, p. 4-5). When commercial plants are built, they are expected to process approximately 125,000 tons of shale and produce 100,000 barrels of oil per day. Such an installation would cost an estimated $524 million to $578 million (Oil Daily, 1972).

In addition to the problems of scaling up from demonstration plants to plants of full commercial size, other serious problems, such as the satisfactory disposal of the spent shale and the acquisition of the necessary large amounts of water, must be dealt with. Water supply will be a particular problem because the most promising shale deposits are in water-deficient areas.

As the volume of the spent shale will be about 30 percent greater than that of the oil shale originally mined, not all of it can be returned to the mine or excavation. The excess must be disposed of in near-by canyons or be piled on the surface. Such disposal of large volumes of waste presents further problems, for some of it is of very fine particle size and must be prevented from blowing. Disposal must also be planned to prevent the leaching of mineral salts from the shale waste into the adjacent surface waters (Rold, 1972).

For each barrel of oil produced, an estimated 1.2 to 2 barrels of water will be consumed and an additional 0.8 to 0.9 barrel of water would probably be needed in waste disposal. Therefore, to produce 100,000 barrels of synthetic oil per day from shale the use of 15,000 acre-feet of water per year would be required, and 6000 and 9500 acre-feet of it would be consumed in the processing (Rold, 1972, p. 6).

Proposals have been made for the in-situ retorting of oil shale underground. Should technology for such operations be developed, the problem of waste disposal, and perhaps to some degree the water-supply problem, might be alleviated.

Even if operations should begin soon on the six experimental lease tracts, the development of any large capacity for producing oil from shale within the next 10 to 12 years appears unlikely (Oil and Gas Jour., 1972).

Solar Energy

Numerous authors have pointed out in recent years that an enormous amount of energy reaches the earth's surface and is potentially available for use if man could economically harness it for his purposes.

According to Hubbert, solar energy is intercepted by the earth at a mean rate of 17.2×10^{16} watts, or about a million times the total installed electric generating capacity in the United States in 1959 (Hubbert, 1962, p. 3-4, 95). Even with the large growth in generating capacity during the last 13 years, the amount of potential solar energy still remains about 380,000 times the total installed capacity in 1972.

Other authors estimate that the amount of energy that strikes only 0.5 percent of the land area of the United States is more than will be required in the whole country in the year 2000 (Hammond, 1972, p. 1088), a demand estimated by Dupree and West (1972, p. 17) at almost 192,000 trillion Btu.

While the amount of energy arriving at the earth's surface is huge, it is diffused, variable in its rate of arrival, and highly intermittent. These characteristics make it difficult to collect and concentrate in large usable quantities, as well as difficult to store and control.

Solar energy can be made usable by two basic means: (1) the concentration of solar rays to provide heat, and (2) the use of photovoltaic materials that generate an electrical potential when light shines on them. Photovoltaic cells have been used to power satellites, but at a cost estimated at about $2 million per kilowatt. To generate large amounts of power would require gathering the solar energy from wide areas. It has been estimated that a 1-mile square photovoltaic unit located in the Southwest where the sun shines an average of 70 percent of the day would generate at least 210 million kilowatt hours per square mile per year (Thomsen, 1972). Converted to a 24-hour equivalent, this is 24 megawatts (24,000 kilowatts).

Studies indicate that to collect and transfer heat from solar energy to a central power station of 1000-megawatt capacity would require a collecting area of about 30 square kilometers (Hammond, 1972, p. 1089), or 11.58 square miles. U.S. generating capacity in power plants of all types is currently growing at about 25,000 megawatts per year.

Solar energy systems are considered desirable environmentally because they do not involve air pollution or radioactivity hazards. However, the disruption of the normal evaporative and other effects of the sun's rays over large areas could have effects on the ecology of those areas that are largely unknown at this time. The areas involved could undergo undeterminable but significant climatic changes.

Although large-scale use of solar power will require much additional research, solar energy has already been used to a limited degree for space heating. A panel from the National Science Foundation—National Aeronautics and Space Administration noted that the cost of solar heating is currently competitive with the cost of heating by fossil fuels in some parts of the country and could supply as much as 80 percent of their heating needs. Despite the problems which must be solved first, the panel believes that by the year 2020 solar energy could provide 35 percent of heating and cooling in buildings, and could replace 30 percent of the nation's gaseous fuel needs, 10 percent of its liquid fuel needs, and 20 percent of its electrical needs (Hammond, 1973).

To make solar heating equipment commercially available, a 100-million-dollar research and development program, spread over a 10-year period has been proposed. The total solar energy program proposed by the panel would cost an estimated 3.5 billion dollars (Hammond, 1973).

Like other large potential sources, solar energy offers promise of meeting some of our future requirements rather than satisfying any significant portion of our immediate needs.

CONCLUSIONS

The United States in 1973 is confronted with an energy problem of major proportions. The domestic capacity to produce fuels and energy is incapable of meeting the needs, and the nation is being forced to turn to foreign sources to an increasing degree. Such dependence can bring with it serious implications and potential consequences.

The present situation does not result from an actual exhaustion of United States resources and energy potential. However, to increase the availability of resources and to develop the potential that exists will require an increase in the rate of discovery of new reserves, major technological progress, large capital investments, and years of time to develop and implement badly needed new policies and programs.

The people of the United States, as a result of continuous technological accomplishments in the past, have developed a strong belief that technology can overcome all obstacles. The hazards of placing unquestioning faith in the ability of technology to provide immediate solutions were pointed out succinctly by Dr. Philip H. Abelson (1969):

> Great achievements often carry with them the seeds of future failures. Repeated success breeds overconfidence and unwillingness to persist in the hard measures that led to excellence. Prolonged enjoyment of excellence brings indifference and even contempt for it. Examples of these tendencies of human nature can be seen in the current attitudes toward science and technology.
>
> When people witness accomplishments such as those of Apollo 8 and Apollo 9, they are impressed with the power of American technology. They are inclined to say, "If we can do that, we can do anything." They are also inclined to believe that we can do everything—that, given the goal and the money, technology can be bent to the accomplishment of any and all tasks. This is not true. Technology cannot rescue society from unlimited folly—a long-continued population explosion, for example.
>
> Overconfidence in our technology leads to other faulty judgments. As Lee Dubridge has recently pointed out, we have become so accustomed to the almost magical capabilities of technology that we expect instantaneous solutions to all problems, no matter how complicated. This demand is unreasonable, even when the problems are purely technical. When complex social, political, and ethical considerations are additional important factors, rosy expectations are just plain foolish.

Dr. Abelson's words describe with considerable accuracy what appears to be the major basis for the seeming lack of concern that has accompanied the development of the present energy dilemma in the United States during the past few years.

Unfortunately, some of those engaged in various research efforts designed to ease the dilemma have contributed to the overconfidence. To gain support for their research efforts, some evidence or promise of success must be presented to indicate that the research will be worth while. Those who are working to solve some particular aspect of the energy problem have sometimes presented over-optimistic assessments of their particular project. Numerous articles in both the scientific and popular press have optimistically asserted that processes for coal gasification and liquefaction, oil shale development, the breeder reactor, and the technology for widely utilizing geothermal and solar power or other unconventional sources of energy were on the verge of perfection. Having repeatedly received such assurances, large segments of the public were caught by surprise and disbelief when the seriousness of the energy situation became generally apparent.

We have, from experience, learned to doubt those who would have us believe that "the wolf is here" and that there is no solution to our problems. Perhaps, we should display equal scepticism to those who too soon would say "Santa is here."

The United States energy situation can be greatly improved, but not overnight or by magic. It will take much coordinated effort, technologic research, capital investment, public cooperation, and, above all, time.

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