[COMMITTEE PRINT]

ENERGY PROGRAM

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OVERVIEW OF THE ENERGY PROBLEM

PREPARED FOR THE

COMMITTEE ON WAYS AND MEANS
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BY THE STAFF OF THE

JOINT COMMITTEE ON TAXATION

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Introduction

This pamphlet is the second in a series prepared for use by the Committee on Ways and Means during its public hearings and executive sessions on the energy tax proposals recommended to Congress by President Carter.

Overview presents a summary of the major economic issues associated with the energy problem as it is generally viewed now and the economic issues that relate to the several fuels which are sources of energy. In each section, summaries are given of the fuel reserves, production levels, major consumption patterns, prices, profits and growth prospects. None of the sections is intended to be a definitive study of the status and problems in the area covered. Each section should, however, provide the reader with enough background information that will help in preparing for the hearings.

As indicated above, the pamphlet is prepared for use by the members of the Committee on Ways and Means during its hearings and deliberations on the energy tax proposals. The pamphlet also will be made available to the members of the House Ad Hoc Committee on Energy. As is usually the case, the pamphlet will be made available to other interested Members of Congress and the general public.

The first in this series of pamphlets was published on May 3, 1977, and it contained a summary of the administration's energy proposals and a summary of energy legislation in the 94th Congress.

Pamphlet No. 3 will contain a section-by-section description of the administration's energy tax proposals and related tax proposals which were considered during the 94th Congress. The third pamphlet will be published simultaneously with this pamphlet. The Joint Committee staff will prepare other pamphlets on the energy tax proposals and alternative taxes for the use of the Committee on Ways and Means. Those pamphlets will be keyed to specific tax proposals, e.g., residential tax credits, or fuel inefficiency tax, as they are taken up by the Committee on Ways and Means in executive session.

Summary

In the first three sections of the report, the broad outlines of the energy problem facing the United States and the related policy considerations are presented. In sections IV through VIII, specific sources of fuel used to make energy available are discussed, and in section IX projections of the availability of new technology sources of energy are presented.

In section I, the nature of the energy problem is described as being four separate, and yet interrelated, problems. The first is the prospect of eventual depletion of the sources of oil and gas available in the United States. Even if higher prices and sheer luck should result in discoveries of large reservoirs of oil and gas, the ultimate result will simply be delayed; deferral of the inevitable exhaustion of the reserves does not mean that the exhaustion will not occur. The second problem is that higher prices for new oil and gas will encourage exploration and development resulting in discovery of additional reservoirs, but they will also contribute to conservation of known existing supplies as all energy users are forced to economize on such higher costs. Third, the ability of the United States to develop additional domestic reserves of oil and gas and currently available supplies of alternative fuel supplies will reduce the adverse effect in this country from disruptions of foreign supplies, irrespective whether the cause of the disruption is political or anything else. The fourth of the enumerated problems is the variety of environmental concerns associated with the production, processing and use of fuel sources and energy use.

Section II presents some economic perspectives of the energy policies that have been presented so far to deal with the energy problem. Limits and interrelationships are stressed. For example, higher prices for crude petroleum would stimulate higher production from existing wells, simply because of the greater returns to the producer and because the higher costs for secondary and tertiary recovery methods are warranted. That result alone is a more rapid rate of exhaustion of existing reserves. The need to stimulate development at commercially viable levels of alternative sources of fuel and energy before exhaustion of oil and gas supplies is also pointed out.

In section III, it is pointed out that consumption of oil and gas has increased steadily through 1973, and it is not known whether the recent leveling reflects a desire to conserve existing reserves or simply the restrictive effects of the OPEC boycott and the current worldwide industrial depression. U.S. production peaked at the start of the 1970's and has been declining since then, and probably irreversibly so.

Sections IV and V contain further details about the production, consumption and reserves of oil and gas.

Coal is discussed in section VI. The known reserves of coal—from lignite through anthracite—are believed to be sufficient for several centuries at current and prospective rates of production. Both production and consumption have been increasing for the past decade, and the supply of coal has been able to match the demand for it, especially since major coal users have contracted for coal sufficiently far in advance for new mines to be opened in time for delivery of their output to consumers. Derivation of methane and crude petroleum from coal are technologically but not commercially feasible as yet.

Nuclear reactors, which are discussed in section VII, generated 9 percent of U.S. electricity in 1976, and during the uncharacteristically cold weather in January 1977, it generated 11 percent of the electricity that was consumed. The United States has substantially more reactors in operation than any of 10 other non-Communist countries, but uses them less intensively. Electric utilities have virtually ceased placing orders for new reactors because of concern over waste disposal, safety, reprocessing, capital costs and uncertainties over the price and availability of uranium.

Hydroelectric power facilities are discussed in section VIII. They provide 15 percent of electric energy consumption now, in contrast with 30 percent in the 1930's and 1940's. Fewer prime sites remain available for new projects, and concern with the environmental impact of new dam projects has delayed new starts. Completion of existing projects by 1985 will increase hydroelectric capacity by 28 percent.

The last section presents a summary of the potential increases in energy supply from new technologies by the year 2000. Because of the long lead time required for installation of new technologies and for bringing them up to producing levels, new technologies are not expected to provide more than 10 percent of the energy supply by 2000.

I. NATURE OF THE ENERGY PROBLEM

The overall energy problem can be broken down into at least four separate problems: (1) the long-run depletion of the United States' and the world's resources of oil and gas, (2) the vulnerability of the United States and its allies to politically motivated disruptions of energy supplies because they rely on oil imports, (3) the high prices of all sources of energy and the effects on living standards, and (4) the fact that increasing energy supply or reducing demand is often inconsistent with improving the environment. Finding a solution to each of the separate energy problems will be difficult, and a solution to the overall energy problem depends upon the success in solving the separate problems and whether those solutions interact favorably towards an overall solution.

Resource Depletion

Most energy consumed in the United States comes from depletable resources which will soon be much more scarce than they are today, and eventually we will have to convert from these depletable sources of energy to other, more abundant ones. This problem is most serious for oil and gas, which currently accounts for three-quarters of the energy consumed in the U.S. As is discussed below, U.S. oil and gas resources are estimated to be large enough to provide about 45 years of production at current levels; that is, until about the year 2020 (see table 14 below). Estimates of worldwide resources are less certain, but these will probably be largely depleted sometime in the first half of the next century as well.

Such an estimate, if correct, does not imply that we will simply run out of oil and gas at that time. Rather, there will be a gradual decline in U.S. production of oil and gas. Limited quantities of oil and gas will be available, probably at extremely high prices, well into the 21st century. It is possible that the annual rate of U.S. oil and gas production will never attain the peak it reached in 1970 (see table 13 below); however, even if an increase in drilling activity does lead to a higher rate of production for a period of time, there will still be a date when production peaks and after which the inevitable decline will set in.

Even though there is only a finite amount of oil and gas in the ground, the total amount of oil and gas that will eventually be extracted depends on public policies. Unless there are appropriate incentives for exploration, some oil and gas deposits will never be discovered. Also, the fraction of the oil or gas in a particular reservoir that can be extracted economically depends on the price of the oil or gas, the costs of bringing a well to production, and other economic variables.

A problem in determining the appropriate price and tax incentives for increasing oil and gas supplies is that frequently those incentives which tend to increase the total amount of economically recoverable oil and gas resources also tend to increase the rate of extraction of the oil and gas resources which are already economically recoverable. Thus, an incentive for increased immediate supply may well aggravate the problem of the rate of long-run resource depletion, rather than alleviate it.

In order to minimize the disruption resulting from the inevitable transition from oil and gas to other sources of energy, that transition should be spread over as long a period of time as possible. An abrupt transition would be economically disruptive for at least two reasons.

First, the existing stock of capital goods—buildings, machines, automobiles and other durable goods—requires oil and gas, and much of this capital stock will become much less valuable, if oil and gas suddenly were to become unavailable. Thus, if the United States continues to produce capital goods which depend on oil and gas right up to the time when those resources become much less available than they are now, there will be a considerable reduction in living standards in the years immediately after that occurs; however, if existing capital goods are gradually replaced by capital goods that do not depend on oil and gas, there is no reason to expect a major decline in living standards in any particular decade.

Second, we do not now have the technology to produce usable energy from several promising alternative sources at prices competitive with oil and gas at their current prices or the prices expected in the near future, and developing this technology will take time. Thus, in order that it be available at the appropriate time, incentives may have to be provided to stimulate development of that technology before it is actually needed.

The appropriate response to the problem of the eventual depletion of oil and gas resources, therefore, appears to be to stretch out the available oil and gas through conservation, to attempt to increase the amount of economically recoverable oil and gas resources in ways that do not also lead to premature depletion of existing reserves, to convert the existing petroleum-based capital stock gradually into one that can rely on alternative energy sources, and to stimulate development of technologies that permit the production and use of alternative sources of energy.

Supply Disruption

Because the United States depends on imported oil for a large percentage of its oil supply (42 percent in 1976 and about half in early 1977) and because only a few countries are the sources of worldwide oil exports, we are vulnerable to politically motivated supply disruptions, such as the Arab oil embargo of 1973–74. Several of our major allies are almost totally dependent on oil imports (see table 16 below). Unlike the problem of resource depletion, the threat of supply disruptions is potentially an immediate one. Such dependence on oil imports from a few countries places serious constraints on U.S. foreign policies.

One response to the threat of supply disruptions is to create a large strategic reserve of oil. This is now being done pursuant to legislation enacted in the 94th Congress. Another response is to diversify our sources of oil imports, and those of our allies, by encouraging exploration for and development of oil reserves in non-Arab countries who would be more reliable suppliers.

Reducing oil imports also reduces our vulnerability to a supply disruption. To the extent this is achieved by reducing oil consumption, it is consistent with the policies needed to deal with the problem of depletion of oil resources. In contrast, to the extent that oil imports are reduced by a more rapid exhaustion of U.S. oil reserves, reducing vulnerability to disruptions of foreign supply in the near future is not consistent with stretching out our oil resources to provide a smoother transition to alternative energy sources. Moreover, to the extent that more rapid exhaustion of U.S. oil reserves is not accompanied by effective transition to alternative energy sources, the threat of disruptions of foreign supplies is merely delayed until the United States is more vulnerable to such disruptions.

Energy Prices

Since 1973 energy prices paid by U.S. consumers have risen sharply. Oil and gas prices have roughly tripled, and coal prices have doubled. Were it not for price controls on crude oil produced in the United States and natural gas sold in interstate commerce, the price increases would have been still greater.

High prices for energy have several important economic effects. To the extent they increase faster than other prices, they increase the overall rate of inflation, both directly and by exacerbating any wage-price spiral. They also transfer income from consumers of energy to domestic and foreign energy producers, a redistribution that many people consider undesirable. (However, higher energy prices will, to some extent, lead to higher wages for workers in energy industries, like coal miners, and people may look differently upon this redistribution than upon higher income for energy producers and royaltyholders.) A significant adverse impact of higher prices has been that energy producers, particularly certain foreign governments, have tended to save a large fraction of their additional income, while energy consumers have tended to reduce consumer spending by a large fraction of their loss of income. This large reduction in overall spending was a major cause of the worldwide recession which began in late 1973 and from which the United States and several other major industrial nations have not yet recovered.

High prices, however, also have some beneficial effects. They encourage conservation, increase the production of energy and encourage the development of higher cost energy technology, all of which help deal with the problem of resource depletion and vulnerability to supply disruptions. Also, many policies that attempt to lower energy prices, such as price controls, have distorting economic effects.

Energy and Environmental Quality

Both the production and consumption of certain types of energy lead to considerable amounts of pollution, and since polluting does not affect profitability, the private market economy can not be expected to make the correct decisions about what should be the appropriate trade-off between energy use and environmental quality. Alternative sources of energy present different environmental problems than does the use of oil and gas. Some alternative sources, such as solar power, generate virtually no pollution, but others, like nuclear power, coal and oil shale, present environmental issues that may be quite serious. The environmental impact of alternative energy policies is an important consideration in evaluating their relative merits.

II. POLICY PERSPECTIVES ON THE ENERGY PROBLEM

Concern about the level of U.S. energy use is related to the rate of depletion of such nonrenewable resources as oil and natural gas, the increasing dependence on foreign sources for a larger part of these vital commodities, and the success of research activity devoted to developing alternative energy sourcess which are either nonrenewable or imported. There is a widespread belief that without action by the Federal Government, the production and consumption decisions of individual households and businesses would not sufficiently reflect these concerns.

No energy policy can alter the inevitable depletion of the oil and natural gas reserves of the United States and the world. The issues, therefore, basically involve the timing of the use of various energy sources: Should the United States reduce its use of oil and gas during the present so that more is available for the future? Should the U.S. speed up its use of coal, thus leaving less available for future needs but retaining an oil and gas supply farther in the future? Should the U.S. become more heavily dependent on nuclear energy sources? What would be a desirable relationship between domestic and imported sources of energy? Should the U.S. subsidize and encourage the present use of new technologies before they become economic?

To put these questions in perspective, it is worthwhile to consider what might happen if the market were left to control the pricing and allocation of energy resources. Without price controls, prices of these resources would gradually rise, at a rate somewhat faster than the general rate of inflation. Much of this rise would result from the explicit decisions of the OPEC countries, who are likely to accelerate these prices increases as their reserves near exhaustion.

This price trend would encourage both household and business energy users to adopt consumption and production practices which are less energy intensive. At the same time, higher oil and gas prices would increase the prices that energy users would be willing to pay for alternative energy sources and would thus encourage the development of these sources. The incomes of those owning gas and oil resources would be likely to rise for the immediate future, although they would eventually decline as the resources are depleted.

Although the market would achieve some conservation and would lead to a gradual phase-in of more expensive energy sources as the cheaper ones were used up, the situation still might not be optimal in several respects.

First, the market by itself would be insensitive to the degree of United States dependence on foreign energy sources. Second, investments in the energy area, especially those involving advanced technologies, are often quite risky, and private businesses may be reluctant to undertake a substantial number of promising, but risky, investments. Third, the market may not be able to evaluate an energy shortage in the future as being as serious a problem as does society as a whole.

Fourth, the way in which public utilities are regulated leads to consumer prices for electricity and natural gas that reflect the average cost of energy resources rather than the cost of developing new sources currently. Thus, consumption decisions do not reflect the actual current cost of expanding overall energy production. In addition, the electricity costs of customers of publicly owned utilities are lower than those of other electricity users simply because of the tax laws: publicly owned utilities have access to tax-exempt financing and are exempt from taxes on their profits.

Goals of U.S. Energy Policy

Even those persons who are inclined to rely on the market to guide the allocation of resources may agree that the Federal Government should formulate an explicit policy to affect the production and consumption of energy and allow the market to carry them out. The principal goals of this policy would include conservation, minimizing dependence on imports, and developing new energy sources. Related goals include avoiding sudden shifts from cheap to expensive sources, maintaining a clean environment, maintaining a fair distribution of income, and maintaining full employment. As these goals are discussed, it will become apparent that they are somewhat inconsistent and that tradeoffs among them are necessary.

The principal concern of energy policy is the current rate of depletion of oil and natural gas. Too rapid use of these materials in the present would deprive future generations of the use of oil and gas and a lifestyle that is taken for granted by the current U.S. population. Rapid use may not permit enough time for development of new energy sources sufficient to replace the depleted sources. In addition, without some gradual cutback in the increasing rate of oil and gas use, sudden price rises and dislocations could occur. This is especially likely if price controls are maintained and encourage consumers to continue their current use patterns. The economic and social disruption which occurred during the oil embargo in 1973 provides a preview of what could happen if the United States were suddenly forced to cut back its energy consumption.

Similar concerns are expressed about the vulnerability of the United States to disruptions in the flow of imports. Another episode such as the 1973 experience could cause considerable harm. Although plans are currently underway to build a readily accessible national petroleum reserve, it would be extremely expensive to amass a reserve which would adequately sustain the U.S. economy for more than 6 months or a year. Thus, the most direct way to reduce vulnerability to an embargo is to import less oil. Reducing consumption of oil products and natural gas and increasing domestic supplies would contribute to reducing the demand for imports. Another problem resulting from large dependence on imports is the possibility that oil exporting countries will accumulate large holdings of financial assets which represent a future claim on U.S. goods and services. Unlike the incomes of domestic oil and gas suppliers, those of foreign countries cannot be limited by U.S. income taxes and price regulations.

An important goal of U.S. energy policy is to develop new sources of energy through research, development and demonstration, since these are crucial phases in making new products commercially feasible. To be consistent with the goals just discussed, emphasis should be placed on energy sources which do not have to be imported from foreign countries and which are in abundant supply.

Other economic goals may be somewhat inconsistent with these three primary energy goals, and some compromises may be necessary. For example, the United States is firmly committed to maintaining and improving the cleanliness of the environment, and cutting down on energy use will generally contribute to the fulfillment of that goal. But increased coal usage, however, may conflict with that goal unless strict safeguards concerning sulfur dioxide and ash emissions, as well as control of dust originating from coal stockpiles, are established.

Similarly the United States economic policy strongly emphasizes maintenance of full employment and a satisfactory rate of economic growth. Full employment could be jeopardized, if tax revenues from energy taxes were not returned to the economy, or if any shifts of purchasing power from consumers to producers were ignored in designing full employment and energy policies. Current economic growth might be slowed somewhat if energy conservation measures are effective, but this could minimize possible future disruptions in the economy.

Components of U.S. Energy Policy

Current proposals for government action in the energy area center on the following policies: price increases, broad based taxes on particular energy sources, taxes on specific uses, credits and deductions for energy-saving activities, mandatory standards for energy efficiency, and grants for research and development. This section discusses the advantages and disadvantages of the first five of these tools for use in achieving the policy goals discussed earlier. Research and development are not analyzed here because they are a long established way of promoting activities which might be insufficiently engaged in by the private sector.

Higher oil and gas prices

Higher prices have several advantages in furthering the goals of conservation, reduction in imports, and development of new energy sources. From the point of view of both business and household consumers, higher prices provide a direct incentive to find ways to reduce energy consumption. Higher prices would stimulate such direct responses, as reducing thermostat levels and miles driven in automobiles, such indirect responses, as installing insulation, buying more efficient automobiles, and substitution of such other energy sources as solar energy or public transportation. By increasing the prices which consumers would be willing to pay for alternate forms of energy, this policy would enlarge the market for emerging forms of energy. In addition, higher oil and gas prices to consumers would lead to lower consumption of energy derived from gas and oil, somewhat higher domestic production and, lower imports. Higher oil and gas prices to domestic producers of new oil would encourage exploration and development of new fields; higher current prices for existing oil and gas supplies would encourage faster depletion, although the current rate of depletion depends largely on the rate at which prices are expected to increase in the future.

Higher levels and growth of oil and gas prices have several disadvantages, however. The most important is that large transfers of income from consumers to producers would result. Many would object to this as unfair, and some explicit offsetting policies would be necessary in order to maintain full employment. A second disadvantage is that higher prices would result in a reduction of consumers purchasing power. Of course, any policy which restrains energy use is likely to have some adverse impact on the standard of living of the average household.

Broad based taxes

Broad based excise taxes on various energy sources, such as crude petroleum and natural gas, raise the price to the consumer and have the advantage of encouraging the same consumer responses as would higher prices. Consumers would cut back their use, both directly and indirectly, and would search for substitutes, and the markets for alternative energy sources would be stimulated. In addition, much of the income that would have gone to producers under a high price policy would instead go directly to the general fund of the U.S. Treasury.

On the other hand, broad based taxes drive a wedge between the prices paid by consumers and those received by producers, who would have a smaller internal flow of funds to finance exploration for new oil and gas. In addition, some equitable mechanism would have to be found to return the tax revenues to the economy. Thus, broad based taxes can be seen as a compromise between the goals of increased domestic production (and thus lower imports) and equitable distribution of income.

Taxes on specific uses

Many current proposals involve specific uses of energy, for example, gasoline (automobiles), inefficient automobiles, nonessential industrial uses, and utilities. Their main advantage is that they can be targeted to specific users whose response is likely to be relatively large. For example, a tax on commuter parking in urban downtown areas might shift a large number of people from automobiles to public transportation. A gasoline tax, which would increase the price of gasoline, might have the same effect on this group of workers, but the tax would have a smaller effect on gasoline use by rural workers, who have few alternatives to automobile driving. Similarly, industry and utilities might be more responsive to rises in oil and gas prices than homeowners, thus making specific taxes on these uses advantageous.

Although the major consideration of taxes on specific uses is that they are intended to be discriminatory, in practice they may not be discriminating enough. For example, while a gasoline tax penalizes the use of oil by automobiles more than its use by other energy users, it penalizes equally the excessive use of gasoline which could result from driving a large number of miles and that which results from driving in an inefficient automobile. A tax on inefficient automobiles, however, penalizes only the second source of excessive use.

Credits and deductions for energy-saving activities

Tax credits and deductions have the advantage of making individual energy users who respond to these incentives more aware of possible savings from cutting their energy use. The credits and deductions have the disadvantage, however, of increasing demand and tending to increase the prices of the targeted goods and services and of possibly increasing total energy use through increasing output of the energy-saving products.

These price tendencies occur because effective incentives increase the demand for the products which receive the incentive. Unless the industries that supply the products have sufficient spare capacity to meet the increased demand, there will be pressure for prices to rise as some consumers bid up the prices in order to assure early delivery of the product. The higher prices have an additional two-fold effect. Some buyers will be encouraged to delay their purchases until they can more easily pay for them. Producers who will earn some higher profits will be able to reinvest the profits in greater productive capacity, an increased flow of raw materials and other supplies, and a larger workforce.

Simultaneously, the shift in demand induced by the incentives will decrease the demand for energy using technologies, causing a flow of resources away from manufacture of the goods used to implement these technologies. To the extent that the facilities for manufacturing the products experiencing a curtailment in demand are readily convertible to the manufacture of energy conserving products, the shift of resources and products will be less disruptive and less expensive. For energy users who invest in energy-saving activities, however, the tax credit lowers the overall cost of production of their output. If, as most economists believe, these tax reductions are passed through to consumers, then, prices will be reduced and demand stimulated. The increase in energy use resulting from this increased output could offset the saving from the adoption of more energy-efficient technologies.

Mandatory efficiency standards

Mandatory standards are other means to decrease the use of energy in various activities. Thus owners of appliances, automobiles, homes and commercial buildings could be limited to a certain total amount, or rate of use, of oil, gasoline, or electricity per time period. The advantage of standards is that they provide a known quantity of energy reduction; the amount of energy efficiency induced solely by a price increase depends on an uncertain design change by the manufacturer or simply less intensive use of the product. Standards also have the advantage of prohibiting energy uses which may be deemed to be extravagant.

Standards have several disadvantages, however. First, they may not provide incentive to exceed whatever level of efficiency is deemed to be appropriate. Second, they do not ensure that total energy use is curtailed, since they do not discourage the use of more efficient machines. For example, even if an air conditioner is required to be more efficient, an individual might respond to the lower cost of use by simply using it more often.

III. OVERALL ENERGY PICTURE

A useful way to obtain a perspective of the overall energy problem in the United States is to examine statistics on U.S. consumption and production of energy in the years after World War Two.

Energy Consumption

Table 1 show energy consumption in the United States during the period 1947–76. Energy is measured in British thermal units, or Btu's.[1] Energy consumption climbed steadily from 33.0 quadrillion Btu's (or "quads") in 1947 to 74.6 quads in 1973. It declined to 70.9 quads in 1975, a decline of 5.0 percent. This decline was largely reversed in 1976, and energy consumption in that year was 74.3 quads, only slightly below the 1973 peak.

Table 1 also measures energy consumption per dollar of gross national product (GNP). Between 1947 and 1966, energy consumption declined from 70.5 thousand Btu's per dollar of GNP (in 1972 prices) to 57.5 thousand Btu's per dollar. The reason for this decline is that as a person's income grows, he tends to spend a larger absolute amount on energy, but his energy costs tend to be a smaller percentage of income.

TABLE 1.—*Energy consumption in the United States, 1947–76*

Year	Energy consumption (quadrillion Btu's)	Energy consumption per dollar of GNP [1] (thousand Btu's)
1947	33.0	70.5
1950	34.0	63.7
1955	39.7	60.6
1960	44.6	60.5
1965	53.3	57.6
1966	56.4	57.5
1967	58.3	57.9
1968	61.7	58.7
1969	65.0	60.3
1970	67.1	62.4
1971	68.7	62.0
1972	71.9	61.4
1973	74.6	60.4
1974	72.6	59.8
1975	70.9	59.5
1976	74.3	58.8

[1] GNP in 1972 prices.

Sources: *Statistical Abstract of the United States 1976* (1947–72) and *Monthly Energy Review* (1973–76).

[1] A Btu is the amount of energy needed to raise the temperature of one pound of water by one degree Farenheit. A barrel of crude oil, containing 42 gallons, contains 5.8 million Btu's. Natural gas contains about one million Btu's per thousand cubic feet (mcf). Coal contains about 23 million Btu's per short ton.

Nevertheless, the tendency towards lower energy consumption per dollar of GNP was reversed between 1966 and 1970, when energy consumption reached 62.4 thousand Btu's per dollar. This acceleration of energy consumption consisted largely of greater use of natural gas by utilities and industry (see table 19 below), although the declining gasoline mileage of the automobile fleet was a contributing factor. Energy consumption per dollar of GNP resumed its declining tendency after 1970. The stable tendency in energy consumption per dollar of GNP in the last decade suggests that the decline in energy consumption between 1973 and 1976 was the result of the sharp decline in GNP since 1973, rather than the result of any major changes in consumer behavior.

In table 2 U.S. energy consumption in 1974 is compared with that of other industrial countries. (The measure of energy in the second column of table 2 is kilograms of coal-equivalent; that is; other sources of energy are converted to the number of kilograms of coal that would produce the same amount of energy.) The United States consumes at least twice as much energy per capita as any other country. Although Sweden and Switzerland each have higher gross national product per capita than the United States, U.S. energy consumption per capita is 1.97 times that of Sweden and 3.18 times that of Switzerland. Germany has a per capita GNP approximately equal to that of the United States, but it uses only half as much energy per capita. Half of the difference in consumption levels can be attributed to the transportation sector, about evenly divided between the higher efficiency of the European automobile fleets and the generally more extensive use—partly because of greater distances—of automobiles and trucks in the United States. About a quarter of the difference in overall energy consumption is related to differences in the energy consumption in residences, even after making adjustment for differences in climate. Residences in Sweden, Germany and Switzerland are built with greater insulation. In the United States, there is a far greater proportion of single family residences; the rooms are larger; there are more rooms in a residence; the average temperature is higher, and the whole house is heated. Air conditioning is not used as extensively in Europe.

TABLE 2.—*Energy consumption per capita in various countries, 1974*

Country	Consumption of energy—coal equivalent (million metric tons)	Consumption of energy per capita (kilograms of coal—equivalent)
United States	2,433.5	11,485
Germany	353.0	5,689
United Kingdom	306.5	5,464
France	227.6	4,330
Italy	178.6	3,227
Japan	421.0	3,839
Sweden	47.4	5,804
Switzerland	23.3	3,608
World total	7,953.0	2,100

Source: *Statistical Abstract of the United States 1976*.

U.S. energy consumption by source of energy is presented in table 3. Coal, the most abundant energy resource in the United States, has accounted for a steadily declining share of U.S. energy consumption. The share of natural gas rose sharply until 1971 and has declined since then. The share of electricity generated from nuclear and hydroelectric power has risen in the 1970's, largely as a result of the development of nuclear power.

TABLE 3.—*Percentage distribution of U.S. energy consumption by source, 1950–76*

Year	Percentage share of—			
	Coal	Crude petroleum	Natural gas	Electricity [1]
1950	38.0	39.7	18.1	4.2
1960	22.8	45.0	28.5	3.7
1965	22.3	43.6	30.2	3.9
1970	18.9	44.0	32.8	4.3
1971	17.5	44.5	33.2	4.8
1972	17.3	45.9	32.0	4.9
1973	17.8	46.7	30.2	5.2
1974	17.8	46.1	29.9	6.2
1975	18.3	46.2	28.2	7.2
1976	18.6	47.2	27.3	7.0

[1] From nuclear and hydroelectric power.

Source: *Statistical Abstract of the United States, 1976* (1950–71) and *Monthly Energy Review* (1972–76).

TABLE 4.—*U.S. energy consumption by sector, 1975*

[In quadrillion Btu's]

Sector	Net energy consumption	Gross energy consumption [1]
Household and commercial	17.8	26.5
Industrial	20.5	26.0
Transportation	18.2	18.4
Total	56.5	70.9

[1] Allocates electrical conversion losses to the sector consuming the electricity.

Source: *Monthly Energy Review.*

Energy consumption by the different consuming sectors is shown in table 4. That table shows both net energy consumption, which ignores the substantial amount of energy that is lost in converting fossil fuels to electricity, and gross energy consumption, which allocates these conversion losses to the sector consuming the electricity. U.S. energy consumption is spread fairly evenly over several different uses. The household and commercial sectors consumed 26.5 quads out of the 70.9 quads of energy consumed in the United States in 1975, or 37.4 percent. Slightly more than half of this energy was used for heating, and most of the rest was consumed as electricity. The industrial sector consumed 26.0 quads, or 36.7 percent, largely as boiler fuel or as petrochemical feedstocks. The transportation sector consumed 18.4 quads, or 25.9 percent, largely as gasoline for automobiles.

Energy Consumption by Region and Income Class

The different regions of the country consume proportionately different amounts of the various types of energy. Table 5 shows the percentage distribution of energy consumption by major region of the country for the various energy sources for 1972. The New England, Middle Atlantic, and South Atlantic States consume a smaller share of the total energy but a larger share of the petroleum than their share of the population. The West south-central region, however, consumes a much larger fraction of all sources of energy except coal and hydropower than its share of population.

TABLE 5.—*Energy consumption by region, 1972*

[Percent of total]

Region [1]	Population	Personal income	Consumption of— Petroleum	Coal	Natural gas	Hydro-power-nuclear	Total energy
New England	5. 8	6. 2	8. 6	0. 3	1. 2	4. 5	4. 4
Middle Atlantic	18. 1	20. 1	19. 5	16. 7	8. 4	12. 3	14. 9
East north-central	19. 6	20. 7	15. 9	38. 6	18. 6	7. 1	20. 5
West north-central	8. 0	7. 6	7. 5	7. 1	9. 2	5. 5	7. 9
South Atlantic	15. 3	14. 3	16. 1	17. 4	7. 1	7. 0	12. 8
East south-central	6. 3	4. 9	4. 8	14. 0	5. 4	7. 7	6. 8
West south-central	9. 6	8. 2	11. 7	. 6	32. 8	1. 2	16. 2
Mountain	4. 3	3. 7	4. 3	4. 7	5. 9	8. 9	5. 1
Pacific	13. 0	14. 5	11. 7	. 6	11. 4	45. 9	11. 3
Total	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0

[1] The regions are: New England—Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut. Middle Atlantic—New York, New Jersey, Pennsylvania. East north-central—Ohio, Indiana, Illinois, Michigan, Wisconsin. West north-central—Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas. South Atlantic—Delaware, Maryland, District of Columbia, West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida. East south-central—Kentucky, Tennessee, Alabama, Mississippi. West south-central—Arkansas, Louisiana, Oklahoma, Texas. Mountain—Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada. Pacific—Washington, Oregon, California, Alaska, Hawaii.

Source: U.S. Bureau of Mines.

Table 6 shows the consumption of petroleum products by region for 1973. The New England and the Middle Atlantic States consume a disproportionately large share of the fuel oil, but a relatively small share of the gasoline.

TABLE 6.—*Consumption of petroleum products by region, 1973 (percent of total)*

Region [1]	1972		Consumption of		
	Population	Personal income	Distillate fuel oil	Residual fuel oil	Gasoline
New England	5. 8	6. 2	10. 8	16. 0	4. 9
Middle Atlantic	18. 1	20. 1	23. 3	29. 9	13. 6
East north-central	19. 6	20. 7	18. 3	6. 8	19. 2
West north-central	8. 0	7. 6	7. 9	1. 5	9. 4
South Atlantic	15. 3	14. 3	12. 3	22. 9	16. 4
East south-central	6. 3	4. 9	4. 7	1. 2	6. 8
West south-central	9. 6	8. 2	8. 9	5. 7	11. 3
Mountain	4. 3	3. 7	5. 4	1. 5	5. 4
Pacific	13. 0	14. 5	8. 4	14. 6	12. 9
Total	100. 0	100. 0	100. 0	100. 0	100. 0

[1] The regions are: New England—Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut. Middle Atlantic—New York, New Jersey, Pennsylvania. East north-central—Ohio, Indiana, Illinois, Michigan, Wisconsin. West north-central—Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas. South Atlantic—Delaware, Maryland, District of Columbia, West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida. East south-central—Kentucky, Tennessee, Alabama, Mississippi. West south-central—Arkansas, Louisiana, Oklahoma, Texas. Mountain—Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada. Pacific—Washington, Oregon, California, Alaska, Hawaii.

Source: U.S. Bureau of Mines, and U.S. Department of Transportation.

Table 7 shows data on energy consumption by income class, based on a survey taken in 1972 and 1973. (These data do not take into account the energy price increases after 1973, which have increased the percentage of income spent on energy for all income classes but which have not significantly altered the relationships among the income classes.) Energy consumption rises as income rises but falls as a percentage of income. The decline in energy consumption as a percentage of income is greatest for heating fuels and least for gasoline, with electricity somewhere in between.

TABLE 7.—*Energy consumption by income class, 1972–73*

	Average annual energy use (million Btu's) [1]	Percent of income spent on—			
		All energy [2]	Natural gas	Electricity	Gasoline
Average income:					
$2,500	560	15.2	5.9	5.2	4.0
$8,000	843	7.2	1.9	2.1	3.2
$14,000	1,246	5.9	1.2	1.5	3.2
$24,500	1,573	4.1	.8	1.1	2.2

[1] This includes both energy consumed directly by the household and energy used to produce other goods and services consumed by the household.
[2] This includes only energy consumed directly by the household.

Source: Washington Center for Metropolitan Studies, Lifestyle and Energy Surveys 1972–73; Energy Policy Project of the Ford Foundation, A Time to Choose: America's Energy Future.

Energy Production and Imports

Table 8 shows U.S. energy production, broken down by source. Total U.S. production of energy rose from 34.4 quads in 1950 to a peak of 62.8 quads in 1972 and declined to 60.1 quads in 1975. The extent of U.S. self-sufficiency in energy can be determined by comparing table 8 with table 1. In 1950, the United States was almost entirely self-sufficient in energy. Even as late as 1965, the United States produced 92 percent of its energy requirements. In 1975, however, the United States produced only 85 percent of its energy needs, and preliminary data indicate that the relative self-sufficiency declined to 81 percent in 1976. Table 8 shows that oil and gas production have declined in recent years and that coal, hydroelectric and nuclear power production have all increased. Nuclear power has grown especially rapidly but still accounts for a small share of overall U.S. energy production.

TABLE 8.—*U.S. energy production by source 1950–75*

[In quadrillion Btu's]

Year	Total U.S. production	Petroleum	Natural gas	Coal	Hydropower	Nuclear power
1950	34.4	11.4	6.8	14.6	1.4	
1955	39.1	14.4	10.5	12.7	1.4	
1960	41.6	14.7	14.1	11.1	1.6	
1965	49.1	15.9	17.7	13.4	2.1	
1970	62.5	20.4	24.2	15.1	2.6	0.2
1971	61.7	20.0	24.8	13.6	2.8	.4
1972	62.8	20.0	24.8	14.5	2.9	.6
1973	62.4	19.5	24.7	14.4	2.9	.9
1974	61.3	18.6	23.7	14.7	3.2	1.2
1975	60.1	17.7	22.2	15.5	3.0	1.7

Source: *Statistical Abstract of the United States 1976.*

Uses of Energy by Economic Sector

Energy is used by virtually every sector of the economy; however, there is substantial variation in the extent to which industries use it. This section briefly discusses: (1) the relative consumption of four aggregate energy sources (coal, crude oil and natural gas, petroleum products, and electricity, gas water and sanitary services) by major industry, and (2) the relative importance of energy by industry as a fraction of the value of total output. It should be emphasized that there is only a very limited amount of data that is reliable and consistent on inter-industry uses of energy. The information below is based on the 1971 Input-Output Table of the U.S. Economy.[1]

Relative consumption of energy sources

Table 9 displays the relative consumption of four energy sources by 13 major industry groups that cover the entire economy. The largest purchaser of coal mining products is the electric, gas, water and sanitary services sector at 41.1 percent and manufacturing is the next largest purchaser of coal mining at 38.3 percent. The coal mining industry buys 11.5 percent of its output from itself for subsequent use.

Better than three-fourths (78 percent) of crude oil and natural gas is sold to the petroleum refining industry. The electric industry buys 18 percent.

TABLE 9.—*Energy purchases as percent of all intermediate sales*

Industry	Coal [1]	Crude [2]	Petroleum [3]	Electricity [4]
Agriculture	0.2	(5)	7.5	1.5
Mining	.2	(5)	.6	.9
Coal [1]	11.5	(5)	.2	.2
Crude petroleum and natural gas	(5)	2.4	.2	.8
Construction	(5)	(5)	15.4	.3
Manufacturing	38.3	.3	23.7	25.7
Petroleum refining [3]	.4	78.0	13.2	2.2
Transportation	.4	.2	15.2	2.6
Electricity [4]	41.1	18.0	3.1	35.2
Wholesale trade	.1	(5)	9.1	11.2
Finance	.9	1.1	5.6	4.2
Services	.7	(5)	5.2	11.3
Government enterprises	6.4	(5)	.9	5.7
Total	100.0	100.0	100.0	100.0

[1] Coal includes coal mining.
[2] Crude includes crude petroleum and natural gas.
[3] Petroleum includes petroleum refining and related industries.
[4] Electricity includes electric, gas, water, and sanitary services.
[5] Less than 0.01 percent.

The sale of goods from the petroleum refining industry is less concentrated. Manufacturing buys 23.7 percent of all intermediate sales, construction 15.4 percent, and transportation 15.2 percent.

[1] U.S. Department of Commerce, Bureau of Economic Analysis, *Input-Output Table of the U.S. Economy: 1971* (BEA Staff Paper, No. 28, March 1977).

The sale of goods from electric, gas, water and sanitary services is roughly patterned after the pattern for the petroleum refining industry. Manufacturing purchases about one-fourth of all intermediate sales, the refining industry sells 35.2 percent to itself and wholesale and retail trade each buy about 11 percent of the total intermediate sales.

Industrial energy use in relation to total industrial output

The inter-industry pattern of energy use may also be viewed in relation to the value of total goods sold by the industry. These relative cost relations are displayed in Table 10. Coal is not a large fraction of the value of total goods sold except in the coal industry (10.2 percent), and to a lesser extent (3.3 percent) in the electricity industry. Crude petroleum and natural gas is not a significant portion of industry total output except in the petroleum refining industry (45.3 percent). Petroleum refined products are also not a significant portion of total output except in that industry (17.3 percent). Electric, gas, water and sanitary services are a large portion of total output for itself (19.3 percent) and government enterprises (6.9 percent).

Overall, total energy uses are from 1.1 to 54.4 percent of the value of total output. For manufacturing, 1.8 percent of the value of total sales is in the form of these four energy uses. For construction, the figure is 2.1 percent. For transportation, the cost of energy is 3.4 percent of the value of total sales. However, for electric, gas, water and sanitary services, various energy uses are 30.4 percent of the value of total output. Thus, an increase in the price of energy will in turn materially affect this industry.

TABLE 10.—*Industrial energy use in relation to industrial output*

[In percent]

Industry	Coal [1]	Crude [2]	Petroleum [3]	Electricity [4]	Total energy input as percentage of output
Agr'culture	0.01	(5)	1.8	0.5	2.3
Mining	.1	(5)	1.3	3.2	4.6
Coal [1]	10.2	0.02	.7	1.4	12.3
Crude petroleum and natural gas	(5)	2.4	.2	1.2	3.8
Construction	(5)	(5)	2.0	.06	2.1
Manufacturing	.2	(5)	.6	1.0	1.8
Petroleum refining [3]	(5)	45.3	7.3	1.9	54.4
Transportation	(5)	.03	2.7	.7	3.4
Electricity [4]	3.3	6.7	1.1	19.3	30.4
Wholesale trade	(5)	(5)	.8	1.4	2.2
Finance	(5)	.1	.5	.5	1.1
Serv:ces	(5)	(5)	.5	1.5	2.0
Government enterprises	1.1	(5)	.1	6.9	8.1

[1] Coal includes coal mining.
[2] Crude includes crude petroleum and natural gas.
[3] Petroleum includes petroleum refining and related industries.
[4] Electricity includes electric, gas, water, and sanitary services.
[5] Less than 0.01 percent.

IV. OIL

Oil Consumption

Petroleum accounted for 47 percent of overall U.S. energy consumption in 1976 and for more than 95 percent of energy consumed in transportation. It is, therefore, the most significant single energy source in the United States.

Table 11 shows U.S. oil consumption by sector between 1950 and 1974. Total consumption rose from 2.4 billion barrels per year in 1950 to 6.3 billion barrels in 1973 and declined to 6.1 billion barrels in 1974. (In 1975, oil consumption fell further to 5.9 billion barrels, but in 1976 it regained the 1973 peak.) In 1974, the transportation sector consumed 54.3 percent of U.S. oil, a share that has not changed significantly in the past two decades. The household and commercial sectors consumed 17.4 percent of the oil, and the industrial sector consumed 18.3 percent of it. Nine percent of the oil was used for electrical generation, a percentage that has risen sharply since 1965 when environmental policies began to use oil and gas for electrical generation in place of coal. Curtailments of natural gas service in recent years have also forced some industries and utilities to shift from gas to oil.

TABLE 11.—*U.S. petroleum consumption by sector, 1950–74*

[Amounts in billions of barrels per year]

Year	Total consumption	Sector							
		Household and commercial		Industrial		Transportation		Electrical generation	
		Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
1950	2. 4	0. 5	22. 1	0. 4	18. 6	1. 2	52. 6	0. 1	4. 5
1955	3. 1	. 7	22. 3	. 6	18. 3	1. 7	54. 5	. 1	2. 6
1960	3. 6	. 9	23. 6	. 6	17. 8	1. 9	53. 6	. 1	2. 5
1965	4. 2	1. 0	23. 3	. 7	17. 6	2. 3	54. 1	. 1	2. 8
1970	5. 4	1. 1	21. 0	1. 0	17. 9	2. 9	54. 1	. 3	6. 2
1973	6. 3	1. 2	18. 5	1. 1	18. 1	3. 4	53. 3	. 6	9. 3
1974	6. 1	1. 1	17. 4	1. 1	18. 3	3. 3	54. 3	. 6	9. 2

[1] Total includes miscellaneous sectors.

Source: *Statistical Abstract of the United States 1976.*

Another factor leading to increased oil consumption was the declining gas mileage of U.S. autos in the years prior to 1975. In 1950, cars averaged 15.0 miles per gallon. Mileage fell steadily to 13.3 mpg in 1973, largely as a result of a shift to larger, more powerful vehicles and changes designed to meet antipollution standards. Gas mileage of new cars, however, has improved substantially since 1974, and over a period of years this will be reflected in higher mileage for the fleet of cars on the road. The 1977 models will average about 18 mpg.

The United States consumes much more oil per dollar of GNP than other industrial nations. This fact is shown in table 12. In 1975, the United States consumed 3.92 barrels of oil per thousand dollars of GNP, compared to 2.00 for Germany, 2.07 for France and 3.39 for Italy and Canada.

TABLE 12.—*Oil consumption per dollar of GNP in various countries, 1975*

Country	Petroleum consumption (millions of barrels per year)	Gross national product (billions)	Petroleum consumption per dollar of GNP (barrels per thousand dollars of GNP)
United States	5, 946	$1, 516. 3	3. 92
Japan	1, 355	491. 0	2. 76
Germany	846	423. 0	2. 00
France	701	337. 9	2. 07
United Kingdom	589	228. 8	2. 57
Italy	582	171. 6	3. 39
Canada	536	158. 3	3. 39

Sources: *Monthly Energy Review* and *Statistical Abstract of the United States 1976*.

Oil Production

U.S. crude oil production peaked in 1970 and has declined steadily since then. This fact is shown in table 13, which presents various statistics relating to oil production. In 1976, U.S. production of crude petroleum (including crude oil and natural gas liquids) was 14 percent below the 1970 peak.

Oil is not a renewable resource; the world contains only a finite amount of it Any existing petroleum deposit will be depleted over time as the petroleum is pumped out. Unless this depletion of existing deposits is offset by discovery of new reserves or by use of secondary and tertiary recovery techniques, oil production must decline. However, as the more accessible deposits have been discovered, drillers must drill deeper or in less accessible areas (such as offshore or in Alaska), so that the cost of finding new reserves must increase over time.

TABLE 13.—*U.S. oil production, 1960–76*

Year	Production of crude petroleum (million barrels) [1]	Number of wells drilled (thousands)	Footage drilled (millions of feet)	Percent dry holes	Proved reserves (million barrels) [3]
1960	2,915	44.1	186.4	39.8	31,613
1965	3,291	39.6	178.7	40.3	31,352
1970	4,123	27.2	136.9	39.7	39,001
1972	4,093	26.4	135.5	40.1	36,339
1973	3,995	26.2	136.7	38.5	35,300
1974	3,819	31.5	150.9	37.2	34,250
1975	3,653	37.2	174.4	35.6	32,682
1976	[2] 3,550	39.8	181.9	34.4	30,900

[1] Including natural gas liquids.
[2] Staff estimate based on data for part of year.
[3] Excludes natural gas liquids.

Sources: *Statistical Abstract of the United States 1976, Monthly Energy Review,* American Petroleum Institute.

In the United States, this natural trend towards declining production was augmented in the 1960's and early 1970's by the effect on U.S. oil prices of the availability of inexpensive oil imports. As shown in table 17 below, U.S. crude oil prices grew by only 35 percent between 1950 and 1972, a period in which the consumer price index rose by 74 percent. The combination of the increased difficulty of finding new oil and the decline in the relative price of oil led to a sharp decline in drilling activity. As shown in table 13, the number of wells drilled declined from 44,000 in 1960 to 26,000 in 1973, and the footage drilled fell from 186 million feet to 137 million feet. Except for the sharp increase in proved reserves in 1970 resulting from the Alaskan discovery, reserves have declined steadily since the mid-1960's.

There has been a significant increase in drilling activity since 1973 as a result of the sharp increase in oil prices. Footage drilled increased by 34 percent between 1972 and 1976, and the number of wells drilled rose by 51 percent. However, the additional drilling has not been sufficient to offset the depletion of existing oil reserves, so that proved reserves of crude oil have continued to decline. Indeed, proved oil reserves are now below their level prior to the Alaskan discovery. (Recent trends in crude oil production are discussed further below under the heading of "Oil pricing.")

No one knows how much oil and gas remains to be discovered in the United States or what will be the cost of finding those reserves. Table 14 presents a careful estimate of U.S. oil and gas resources made by the U.S. Geological Survey.

For crude oil, the Geological Survey identified several categories of reserves, based on the degree of certainty about their size. "Proved reserves" are those which can be economically extracted with existing technology. These were estimated to be 34.3 billion barrels, as of the end of 1974, or about 11 years production at the 1974 rate of 3.2

billion barrels per year. (By the end of 1976, proved reserves of crude oil had declined to 30.9 billion barrels.) How much oil can be economically extracted from a particular deposit depends, in part, on the price of the oil, and unfortunately the estimates of proved reserves in table 14 do not take into account the price increases after 1973. Therefore, they are probably understated. Proved reserves also do not include "indicated reserves," which are those economically recoverable with secondary recovery techniques. These amount to slightly more than a year's production.[2] Higher oil prices would also significantly expand the amount of indicated reserves; however, as discussed below, much of the additional oil that would be produced with secondary recovery is classified as "old oil" and hence is now subject to price controls. The existence of these price controls, and the expectation that they may be removed sometime in the future, has probably delayed some secondary recovery investments. It is not clear how large indicated reserves would be at the high prices now prevailing for new oil.

[2] Secondary recovery involves injecting water into an oil field to force the oil into a position where it can be pumped out of producing oil wells. Tertiary recovery involves injecting gas and chemicals, which also may liquefy extremely viscous oil to make it easier to pump out.

TABLE 14.—*Estimated U.S. reserves of oil and gas, Dec. 31, 1974*

	Cumulative production to Dec. 31, 1974	Proved reserves [1]	"Indicated reserves" [2]	"Inferred reserves" [3]	Estimated undiscovered recoverable resources [4]	
Crude oil (billions of barrels):						
Lower 48 onshore	99.9	21.1	4.3	14.3	29– 64	(44)
Alaska onshore	.2	9.9	0.0	6.1	6– 19	(12)
Lower 48 offshore	5.6	3.1	.3	2.6	5– 18	(11)
Alaska offshore	.5	.2	0.0	.1	3– 31	(15)
Total	106.1	34.3	4.6	23.1	50–127	(82)
Natural gas liquids (billions of barrels)	15.7	6.4	(5)	6.0	11– 22	(16)
Natural gas (trillions of cubic feet):						
Lower 48 onshore	446.4	169.5	(5)	119.4	246–453	(345)
Alaska onshore	.5	31.7	(5)	14.7	16– 57	(32)
Lower 48 offshore	33.6	35.8	(5)	67.4	26–111	(63)
Alaska offshore	.4	.1	(5)	.1	8– 80	(44)
Total	480.8	237.1	(5)	201.6	322–655	(484)

[1] Proved reserves are those which can be economically extracted with existing technology.
[2] Indicated reserves are those which are economically recoverable with secondary recovery.
[3] Inferred reserves are estimated additional reserves resulting from extensions of existing fields, revision of estimates, and so forth.
[4] There is only an estimated 5-percent probability that undiscovered recoverable resources are below the lower end of the range, and a 5-percent probability that they are above its upper end. The figure in parentheses is the statistical mean.
[5] Not applicable.

Note: These estimates do not take into account oil and gas price increases after 1973.

Source: Department of the Interior, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," 1975.

"Inferred reserves" are less certain than either proved or indicated reserves but are very likely to exist. These are the reserves which will very probably be added as a result of extension of existing oil fields, revisions of estimates (which are usually upward revisions) and other similar reasons. These are estimated to be 23.1 billion barrels. Thus, according to the Geological Survey, the total known U.S. oil reserves were about 62 billion barrels at the end of 1974, or about 19 years production.

The Geologial Survey estimates that proved and indicated reserves of natural gas liquids (used to make propane and other close substitutes for oil) were 12.4 billion barrels, or 20 years' production at the 1974 rate of 616 million barrels.

The main uncertainty concerns oil and gas resources which have not yet been discovered. The Geological Survey has made estimates of these undiscovered resources, which are also shown in table 14. Because of the uncertainty involved, these estimates are expressed as a probability distribution. The Survey estimates that there is only a 5-percent probability that undiscovered recoverable resources of crude oil are below 50 billion barrels and a 5-percent probability that they are above 127 billion barrels. The estimate of the mean (or expected value) of the probability distribution is 82 billion barrels.[3] If we ultimately discover 82 billion more barrels of oil, then total reserves of crude oil will turn out to be 144 billion barrels, or 45 years of 1974 production. This would mean that if the United States produces oil at 1974 rates, it would run out of crude oil by about the year 2020. However, there is a 5-percent chance that existing reserves and undiscovered resources total only 112 billion barrels, in which case the United States would run out of crude oil at current rates of production by 2010.

The Survey estimates are similar for natural gas liquids. At their mean value, reserves and undiscovered resources would be 46 years of 1974 production.

Currently, 62 percent of proved oil reserves are onshore in the lower 48 States and 29 percent are onshore in Alaska. Only 10 percent of proved reserves are offshore. The Survey developed estimates, however, that 32 percent of undiscovered recoverable crude oil resources are offshore, and that more than half of this offshore oil lies off Alaska. Slightly more than half of estimated undiscovered recoverable oil resources are onshore in the lower 48 States. Since oil and gas exploration is more costly offshore than it is onshore, the costs of finding new oil will be much higher in the future than it has been in the past.

Oil production also involves refining the crude oil after it is extracted. The United States has the capacity to refine about 15.6 million barrels of oil per day (mbd), compared to 1976 consumption of 17.3 mbd. Thus, the United States is dependent on foreign refineries for at least 10 percent of petroleum products. There is, however, a large surplus of refining capacity worldwide. At the end of 1976, worldwide refining capacity was 72.2 mbd, while production of crude oil was 56.8 mbd.

[3] The mean of a probability distribution for a particular random variable is the sum of the possible values for that variable weighted by the probaility associated with that value.

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Oil Imports

The inevitable result of rapidly increasing U.S. oil consumption and declining domestic production has been a rapid growth in oil imports. The trend of oil imports is shown in table 15. Until 1965, the United States had spare productive capacity for crude petroleum that exceeded its oil imports, so that the United States was self-sufficient in oil. Oil production, however, has proceeded at full capacity since 1972, and in 1976 imports rose to 7.3 million barrels per day (mbd), or 42 percent of consumption. In addition, many of our allies are almost totally dependent on oil imports. Japan, Germany, France and the United Kingdom relied on imports for more than 95 percent of oil needs in 1975. Their reliance on imports will continue in the future, although production of North Sea oil soon may make the United Kingdom self-sufficient. (See table 16.)

TABLE 15.—*U.S. oil demand, supply and imports, 1955–76*

[In millions of barrels per day]

Year	U.S. demand for petroleum	U.S. production of crude oil	U.S. production of natural gas liquids	U.S. spare capacity for crude oil	U.S. oil imports
1955	8.49	6.81	.77	1.78	1.25
1956	8.82	7.15	.80	2.08	1.44
1957	8.86	7.17	.81	2.78	1.57
1958	9.15	6.71	.81	2.60	1.70
1959	9.49	7.05	.88	2.67	1.78
1960	9.81	7.04	.93	2.71	1.82
1961	9.99	7.18	.99	2.75	1.92
1962	10.41	7.33	1.02	2.63	2.08
1963	10.75	7.54	1.10	2.67	2.12
1964	11.03	7.61	1.16	2.73	2.26
1965	11.52	7.80	1.21	2.45	2.47
1966	12.10	8.30	1.28	2.24	2.57
1967	12.57	8.81	1.41	2.12	2.54
1968	13.40	9.10	1.50	1.90	2.84
1969	14.15	9.24	1.59	1.38	3.17
1970	14.71	9.64	1.66	1.33	3.42
1971	15.23	9.46	1.69	.69	3.93
1972	16.37	9.47	1.74	.20	4.74
1973	17.31	9.21	1.74	----------	6.26
1974	16.65	8.77	1.69	----------	6.11
1975	16.29	8.63	1.63	----------	6.03
1976	17.33	8.13	1.60	----------	7.27

Source: Independent Petroleum Association of America (1955–71) and *Monthly Energy Review* (1972–76).

Table 16 shows the country-of-origin for the oil imports of the United States and several other countries for 1975. Out of its oil imports of 6.0 mbd in 1975, the United States imported 1.8 mbd from

Arab countries. However, this actually understates U.S. dependence, since we import 0.8 mbd from Canada, which itself imports 0.3 mbd from Arab countries. If U.S. imports from Canada that are offset by Canadian imports from Arab countries are counted as U.S. imports directly from Arab countries, U.S. dependence on Arab imports in 1975 would rise to 2.1 mbd, or 13 percent of U.S. oil consumption. This dependence on Arab suppliers clearly increased in 1976. Japan, Germany and the United Kingdom depended on Arab countries for about one-half of their oil, and France depended on the Arab countries for three-fourths of its oil.

TABLE 16.—*Oil imports by country of origin, 1975* [1]

[In million barrels per day]

Importing country	Arab countries	Iran	Venezuela	Indonesia	Canada	Nigeria	Total imports	Imports as percent of consumption
United States	1, 770	500	1, 040	450	800	820	6, 030	37. 0
Japan	2, 540	1, 180	10	560	----------	60	5, 010	99. 2
Germany	1, 170	290	50	----------	----------	200	1, 970	95. 3
France	1, 550	270	40	----------	----------	180	2, 190	98. 3
United Kingdom	990	360	70	----------	----------	120	1, 830	98. 9
Canada	300	200	280	----------	----------	20	890	[2] 5. 8

[1] Imports of refined products are traced to source of crude oil.
[2] Imports minus exports as a percentage of consumption.

Source: *International Economic Report of the President, 1976.*

Oil Prices

Prices of oil and natural gas produced in the United States are shown in table 17. The price of crude oil declined by 28 percent relative to the overall price level between 1950 and 1972. Since 1972, however, prices at the well head have risen by 80 percent relative to the overall price level.

As of December 1976, the price of imported oil to the refiner was $13.72 per barrel, including the costs of transporting the oil to the U.S. refinery. This price does not take into account the price increase announced at the end of 1976, which was 5 percent for Saudi Arabian oil and 10 percent for most other imported oil. That increase should raise the price to about $14.25 per barrel. Domestic oil prices, including costs of transportation to the refinery, averaged $9.29 per barrel. If price controls were eliminated, the price of domestic oil could be expected to rise to the price of imports, or by about $5 per barrel. This would increase oil costs to consumers by about $18 billion. Oil profits and royalties would not rise by this amount because of income and severance taxes on this income.

Currently, crude oil prices are controlled in several "tiers." Lower tier oil is controlled at a price averaging about $5.17 per barrel, the May 1973 price plus $1.35 per barrel. (The $5.17 figure is an average of prices ranging from about $2.50 to about $7.50 per barrel, depending on the quality and location of the oil.) Upper tier oil is controlled at a price averaging $11.64 per barrel. Stripper oil is not subject to price controls and sells at the world price.

TABLE 17.—*Prices of crude oil and natural gas produced in the United States, 1950–1976*

Year	Prices per barrel of crude oil		Prices per thousand cubic feet of natural gas	
	Current prices	1972 prices	Current prices	1972 prices
1950	$2.51	$4.68	6.5¢	12.1¢
1955	2.77	4.54	10.4	17.1
1960	2.88	4.19	14.0	20.4
1965	2.86	3.85	15.6	21.0
1970	3.18	3.48	17.1	18.7
1972	3.39	3.39	18.6	18.6
1973	3.89	3.68	21.6	20.4
1974	6.87	5.90	30.4	26.1
1975	7.67	6.03	44.5	35.0
1976	8.11	6.06	NA	NA

NA= not available.

Source: *Statistical Abstract of the United States 1976* and *Monthly Energy Review.*

The price controls work as follows: For each property, producers must determine a base production control level (BPCL). This is the lesser of the average production in calendar years 1972 or 1975.

For each month, the upper tier crude oil, or new oil, for a property is the number of barrels produced from that property in that month in excess of the BPCL. Stripper oil is all oil produced on a property whose average production is 10 barrels per day or less. Lower tier crude oil, or old oil, is all oil that is neither new oil or stripper oil. Fifty percent of U.S. oil is old oil: 37 percent is new oil and 13 percent is stripper oil. Costs of oil to different refiners are made more equal through a federal old oil entitlement program.

This system of price controls is intended to encourage increased production. Any oil produced from a property where there was no production in 1972 is classified as new oil and commands a high price. In addition, to the extent that a producer can increase production from his property above the BPCL, the excess production can be sold at new oil prices.

There are, however, two major problems with the price controls. First, since oil reserves have a natural tendency to become depleted, production from a given property tends to fall over time, and the production from most properties in 1976 and future years will be below the BPCL. Thus, for most properties, part of any increase in production will get classified as old oil, not new oil, a problem which will become more serious as production from existing reserves falls progressively farther below the BPCL.[4] Second, some enhanced recovery techniques involve producing oil at a slower rate for a longer period of time. For example, there might be a field of 36 wells, each producing 50 barrels per day. Secondary recovery could involve stopping production from 6 of those wells and injecting water into the field through them, which could increase average production in the remaining 30 wells to (say) 55 barrels per day. Because of the water injections, however, production at the new 55-barrel rate would continue for a much longer time than production at the 50-barrel rate without water injection. Thus, secondary recovery would increase total production over the life of the oil field even though the rate of production initially would decline. In this case, all of the additional oil would be classified as old oil and sold at low controlled prices.

Oil and Gas Profits

One effect of the increase in oil and gas prices since 1972 has been an increase in the profits of oil and gas producers. Table 18 presents data on the profits of the major oil and gas companies between 1972 and 1976.

Profits have behaved differently for the different segments of the industry. Before-tax profits have increased the most for independent producers of crude oil and for those integrated companies who emphasize crude oil production. The increases in after-tax profits shown in table 18 include the effects of the sizable tax increase on oil and gas producers in the Tax Reduction Act of 1975, which eliminated percentage depletion for oil and gas for integrated oil companies and reduced it for many smaller producers. Producers, however, continue to benefit from favorable tax treatment of exploration and development costs.

[4] In addition, increased production does not get classified as new oil until any prior deficiencies in production below the BPCL have been made up, so that a producer whose output has been below the BPCL for a period of time has still less incentive to increase production.

Oil refiners and marketers have not experienced significant increases in profits because of the slow growth in demand for petroleum products, the worldwide surplus of refining capacity, and U.S. price controls. Producers of foreign oil received large inventory profits in 1973, but their profits have not been extraordinarily high since then. Their taxes were increased in the Tax Reduction Act of 1975 and again in the Tax Reform Act of 1976.

TABLE 18.—*Oil and gas profits, 1972–76*

Company	Profits after taxes (millions of dollars)					Percent change, 1972–76
	1972	1973	1974	1975	1976	
Integrated companies—international:						
British Petroleum	176	760	1, 118	293	NA	[1] +66. 5
Exxon	1, 532	2, 443	3, 030	2, 503	2, 640	+72. 3
Gulf	447	800	1, 065	700	816	+82. 6
Mobil	574	849	1, 047	810	NA	[1] +49. 8
Royal Dutch	270	701	1, 053	899	NA	[1] +233. 0
Standard Oil of California	547	844	970	773	880	+60. 9
Texaco	889	1, 292	1, 545	831	870	−2. 2
Subtotal	4, 435	7, 689	9, 828	6, 809		[1] +53. 5
Integrated companies—domestic:						
Amerada Hess	46	246	202	128	153	+230. 1
Ashland	68	85	110	119	139	+104. 4
Atlantic Richfield	193	270	475	350	575	+198. 8
Cities Service	99	136	204	138	217	+119. 0
Clark	8	31	7	5	9	+12. 7
Continental	170	243	307	331	470	+176. 2
Getty	76	135	289	257	259	+239. 6
Kerr-McGee	51	63	116	131	134	+165. 0

Marathon	80	129	170	128	196	+145.4
Murphy	14	48	66	40	49	+241.7
Phillips	148	230	430	343	412	+177.6
Quaker State	15	20	21	23	26	+69.0
Skelly	38	44	108	90	NA	[1] +138.2
Standard Oil of Indiana	375	511	958	787	893	+138.3
Standard Oil of Ohio	60	74	126	127	137	+129.4
Sun	155	230	378	220	356	+130.2
Union	122	180	288	233	269	+120.4
United Refining	4	6	5	6	3	−27.4
Subtotal	1,722	2,681	4,260	3,456		[1] +100.7
Crude producers:						
General Amer	15	11	24	23	NA	[1] +51.1
Louisiana Land Ex	63	70	107	88	97	+53.5
Mesa Pete	17	19	5	19	31	+84.4
Superior Oil	5	42	61	52	NA	[1] +916.2
Subtotal	100	142	197	182		[1] +82.0
Total	6,257	10,512	14,285	10,447		[1] +67.0

[1] Percent change from 1972 to 1975. NA=not available.

V. NATURAL GAS

Gas Consumption

Table 19 shows natural gas consumption by sector between 1950 and 1975. Between 1950 and 1970, gas consumption grew at an extraordinarily rapid rate, but it peaked in 1972 and has declined since then. In 1975, the residential sector consumed 24 percent of U.S. natural gas, and utilities and industry used 46 percent of the gas. The residential sector has been largely insulated from the decline in gas consumption in recent years because Federal regulations allocate available gas to residences and away from industry when there are shortages.

Proved reserves of natural gas have declined sharply from 291 trillion cubic feet in 1970 to 228 trillion cubic feet in 1975. (In 1976, reserves declined further to 216 trillion cubic feet.) Because companies will construct pipelines only if they are assured of gas supplies for many years, most natural gas is sold under long-term contracts which require producers to dedicate certain reserves to particular pipelines or to particular consumers. Many of these contracts fix the price of gas well below the world market price for other sources of fuel. As a result, gas producers have been depleting existing gas reserves at a very rapid rate in an attempt to satisfy current demands of gas consumers, but gas producers have been unwilling to develop new reserves and commit them under long-term contracts, presumably in the expectation that gas prices will rise still further.

The result has been natural gas shortages which have resulted in curtailments of gas supplies to certain users. These were particularly severe in the cold winter in 1976–77, when gas shortages required layoffs in many industries.

TABLE 19.—*Natural gas consumption by sector, 1975*

[Trillions of cubic feet]

Year	Total Consumption	Residential	Commercial	Utilities	Field use	Refineries	Pipeline fuel	Other industrial	Proved reserves
1950	6.0	1.2	0.4	0.6	1.2	0.5	0.1	2.0	185
1955	9.1	2.1	.6	1.2	1.5	.6	.2	2.8	224
1960	12.5	3.1	1.0	1.7	1.8	.8	.3	3.8	264
1965	16.0	3.9	1.4	2.3	1.9	.9	.5	5.1	286
1970	22.0	4.8	2.1	3.9	2.3	1.0	.7	7.2	291
1971	22.7	5.0	2.2	4.0	2.3	1.1	.7	7.4	279
1972	23.0	5.1	2.3	4.0	2.4	1.1	.8	7.4	266
1973	23.0	4.9	2.3	3.6	2.4	1.1	.7	8.0	250
1974	22.1	4.8	2.3	3.4	2.4	1.0	.7	7.6	237
1975	20.4	4.9	2.3	3.1	2.3	.9	.6	6.3	228

Source: *Statistical Abstract of the United States 1976.*

As shown in table 14 above, natural gas resources are estimated to be approximately as abundant as crude oil. Their expected value is about 45 years worth of 1975 consumption. However, a larger percentage of undiscovered recoverable gas resources are expected to be onshore in the lower 48 States than is the case with oil.

Natural Gas Prices

The price of natural gas sold in interstate commerce is regulated by the Federal Power Commission (FPC). In mid-1976, the average wellhead price of natural gas sold to major interstate pipelines was 44 cents per thousand cubic feet (mcf). These pipelines purchased about one-half of the gas produced in the United States. The price ceiling for natural gas is now $1.44 per mcf, but the average price at which interstate gas is sold is considerably less than this because many prices are set by old long-term contracts. The price of gas sold within the producing State is considerably higher than $1.44, and in some cases exceeds $2.00, so that producers dedicate relatively little new gas to interstate commerce. The principal exception is offshore gas, which is subject to FPC regulation no matter where it is sold.

The distortions resulting from the existing methods of pricing natural gas can be seen by comparing gas and oil prices. In November 1976, the average price of gas sold to residences was $1.97 per mcf. Since one barrel of distillate fuel oil contains 5.8 times as much energy as one mcf of gas, this natural gas price is equivalent to a price of $11.43 per barrel for distillate fuel oil. That month, the price of heating oil was $17.50 per barrel, so that residential gas prices were only two-thirds of heating oil prices and incentives for gas conservation were correspondingly weaker.

In July 1976, the price of gas sold by the major interstate pipelines to industrial users averaged $.943 mcf, equivalent to $5.79 per barrel for residual fuel oil, but residual fuel oil itself sold for an average price of $10.74 per barrel. Thus, those companies lucky enough to be customers of an interstate pipeline incur half the energy cost of their competitors who must rely on fuel oil.

Table 15 above shows the history of natural gas prices since 1950. In recent years, gas prices have risen sharply, but they are still well below equivalent crude oil prices.

VI. COAL

Coal is the most abundant fossil fuel available in the United States. The known reserves are sufficient to meet domestic needs for several centuries. Such abundance is specially important now in view of the prospective substantial price increases for petroleum, natural gas and their products and the prospect that future increases in proved oil and gas reserves will not keep pace with oil and gas consumption. Coal is most important immediately because of its suitability as a fuel substitute for oil and gas and because coal has potential use also as a source for synthetic oil and gas. Its drawbacks are the environmental impact and cost of its extraction, transportation and use.

Coal Reserves

Domestic coal reserves are approximately 437 billion tons (see table 20) and are found in 30 States. Slightly more than half the reserves, 234 billion tons or 54 percent are located in western states and the remainder, 203 billion tons or 46 percent, are in eastern states. About two-thirds of the total is found in 5 states—Montana, Illinois, Wyoming, West Virginia and Pennsylvania, in order of size of reserve.

About 46 percent, or 200 billion tons, has a sulfur content below 1 percent, which is below the level deemed satisfactory to avoid air pollution. Almost all of the coal reserves in Montana and 60 percent of those in Wyoming are in this category. Almost the same amount of coal reserves, 186 billion tons, has a high sulfur content and is evenly divided between reserves with a sulfur content of 1 to 3 percent and a sulfur content greater than 3 percent.

TABLE 20.—*Demonstrated coal reserve base of the United States on Jan. 1, 1974, total underground and surface*

[Million tons]

State	Sulfur range, percent				
	<1.0	1.1–3.0	>3.0	Unknown	Total [1]
Alabama	624.7	1,099.9	16.4	1,239.4	2,981.8
Alaska	11,458.4	184.2			11,645.4
Arizona	173.3	176.7			350.0
Arkansas	81.2	463.1	46.3	74.3	655.7
Colorado	7,475.5	786.2	47.3	6,547.3	14,869.2
Georgia	.3			.2	.5
Illinois	1,095.1	7,341.4	42,968.9	14,256.2	65,664.8
Indiana	548.8	3,305.8	5,262.4	1,504.1	10,622.6
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kansas		309.2	695.6	383.2	1,388.1
Kentucky, East	6,558.4	3,321.8	299.5	2,729.3	12,916.7
Kentucky, West	.2	564.4	9,243.9	2,815.9	12,623.9
Maryland	135.1	690.5	187.4	34.6	1,048.2
Michigan	4.6	85.4	20.9	7.0	118.2

Missouri		182. 0	5, 226. 0	4, 080. 5	9, 487. 3
Montana	101, 646. 6	4, 115. 0	502. 6	2, 166. 7	108, 396. 2
New Mexico	3, 575. 3	793. 4	. 9	27. 5	4, 394. 8
North Carolina				31. 7	31. 7
North Dakota	5, 389. 0	10, 325. 4	268. 7	15. 0	16, 003. 0
Ohio	134. 4	6, 440. 9	12, 634. 3	1, 872. 0	21, 077. 2
Oklahoma	275. 0	326. 6	241. 4	450. 5	1, 294. 2
Oregon	1. 5	. 3			1. 8
Pennsylvania	7, 318. 3	16, 913. 6	3, 799. 6	2, 954. 2	31, 000. 6
South Dakota	103. 1	287. 9	35. 9	1. 0	428. 0
Tennessee	204. 8	533. 2	156. 6	88. 0	986. 7
Texas	659. 8	1, 884. 6	284. 1	444. 0	3, 271. 9
Utah	1, 968. 5	1, 546. 7	49. 4	478. 3	4, 042. 5
Virginia	2, 140. 1	1, 163. 5	14. 1	330. 0	3, 649. 9
Washington	603. 5	1, 265. 5	39. 0	45. 1	1, 954. 0
West Virginia	14, 092. 1	14, 006. 2	6, 823. 3	4, 652. 5	39, 589. 8
Wyoming	33, 912. 3	14, 657. 4	1, 701. 1	3, 060. 3	53, 336. 1
Total	200, 181. 1	92, 997. 6	92, 671. 1	50, 837. 7	436, 725. 4

[1] Data may not add to totals shown because of independent rounding.

Source: U.S. Bureau of Mines, *Minerals Yearbook*, 1974, p. 354

TABLE 21.—*Demonstrated coal reserve base of the United States on Jan. 1, 1974, by underground method of mining*

[Million tons]

State	Sulfur range, percent				
	<1.0	1.1–3.0	>3.0	Unknown	Total [1]
Alabama	589.3	1,016.7	14.8	176.2	1,798.1
Alaska	4,080.8	163.2			4,246.4
Arkansas	43.3	310.3	29.2	19.1	402.4
Colorado	6,751.3	640.0	47.3	6,547.3	13,999.2
Georgia	.3			.2	.5
Illinois	1,034.7	5,848.4	33,647.6	12,908.4	53,441.9
Indiana	443.5	2,746.6	4,355.1	1,402.5	8,948.5
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kentucky, East	5,042.7	2,391.9	212.7	1,814.0	9,466.5
Kentucky, West		386.6	7,226.4	1,107.1	8,719.9
Maryland	106.5	623.9	171.2		901.9
Michigan	4.6	84.9	20.8	7.0	117.6
Missouri		134.2	3,590.2	2,350.5	6,073.6

Montana	63, 464. 2	1, 939. 8	456. 2		65, 834. 3
New Mexico	1, 894. 3	214. 1	. 9	27. 5	2, 136. 5
North Carolina				31. 3	31. 3
Ohio	115. 5	5, 449. 9	10, 109. 4	1, 754. 1	17, 423. 3
Oklahoma	154. 5	238. 5	202. 6	264. 3	860. 1
Oregon	1. 0				1. 0
Pennsylvania	7, 179. 7	16, 195. 2	3, 568. 1	2, 864. 8	29, 819. 2
Tennessee	139. 3	370. 0	101. 4	53. 9	667. 1
Utah	1, 916. 2	1, 397 6	6. 8	460. 3	3, 780. 5
Virginia	1, 728. 5	945. 4	12. 0	283. 3	2, 970. 7
Washington	431. 0	957. 8	13. 2	42. 9	1, 445. 9
West Virginia	11, 086. 6	12, 583. 4	6, 552. 9	4, 142. 9	34, 377. 8
Wyoming	20, 719. 5	4, 535. 1	1, 275. 6	2, 955. 0	29, 490. 8
Total [1]	126, 928. 8	59, 400. 2	73, 720. 2	39, 761. 6	299, 839. 7

[1] Data may not add to totals shown because of independent rounding.

TABLE 22.—*Demonstrated coal reserve base of the United States on Jan. 1, 1974, by surface method of mining*

[Million tons]

State	Sulfur range, percent				
	<1.0	1.1–3.0	>3.0	Unknown	Total [1]
Alabama	35.4	83.2	1.6	1,063.2	1,183.7
Alaska	7,377.6	21.0			7,399.0
Arizona	173.3	176.7			350.0
Arkansas	37.9	152.8	17.1	55.2	263.3
Colorado	724.2	146.2			870.0
Illinois	60.4	1,493.0	9,321.3	1,347.8	12,222.9
Indiana	105.3	559.2	907.3	101.6	1,674.1
Kansas		309.2	695.6	383.2	1,388.1
Kentucky, East	1,515.7	929.9	86.8	915.3	3,450.2
Kentucky, West	.2	177.8	2,017.5	1,708.8	3,904.0
Maryland	28.6	66.6	16.2	34.6	146.3
Michigan		.5	.1		.6
Missouri		47.8	1,635.8	1,730.0	3,413.7

Montana	38, 182. 4	2, 175. 2	46. 4	2, 166. 7	42, 561. 9
New Mexico	1, 681. 0	579. 3			2, 258. 3
North Carolina				. 4	. 4
North Dakota	5, 389. 0	10, 325. 4	268. 7	15. 0	16, 003. 0
Ohio	18. 9	991. 0	2, 524. 9	117. 9	3, 653. 9
Oklahoma	120. 5	88. 1	38. 8	186. 2	434. 1
Oregon	. 5	. 3			. 8
Pennsylvania	138. 6	718. 4	231. 5	89. 5	1, 181. 4
South Dakota	103. 1	287. 9	35. 9	1. 0	428. 0
Tennessee	65. 5	163. 2	55. 2	34. 1	319. 6
Texas	659. 8	1, 884. 6	284. 1	444. 0	3, 271. 9
Utah	52. 8	149. 1	42. 6	18. 0	262. 0
Virginia	411. 6	218. 1	2. 1	46. 7	679. 2
Washington	172. 5	307. 7	25. 8	2. 2	508. 1
West Virginia	3, 005. 5	1, 422. 8	270. 4	509. 6	5, 212. 0
Wyoming	13, 192. 8	10, 122. 3	425. 5	105. 3	23, 845. 3
Total [1]	73, 252. 3	33, 597. 4	18, 950. 9	11, 076. 1	136, 885. 7

[1] Data may not add to totals shown because of independent rounding. Source: U.S. Bureau of Mines, *Mineral Yearbook*, 1974, p. 353.

Most of the coal reserves require the higher cost underground mining methods for recovery. As shown in tables 21 and 22, 300 billion tons, or 69 percent, will require underground mining techniques and the remainder may be recovered by surface mining. Sixty-four percent of the one percent or lower sulfur content and the same portion of the 1 to 3 percent sulfur content require underground mining techniques.

Production, Consumption and Transportation

Domestic production in 1977 is estimated to reach 700 million tons, an increase of more than 5 percent over 1976 production. As shown in table 23, production has increased by 155 million tons, or 28 percent, since 1968, with two-thirds of the increased production levels occurring after 1973. Consumption also increased by 155 million tons since 1968. Coal consumption by electric utilities increased 185 million tons during the period, thereby absorbing all of the increased production and offsetting almost all of the decreased consumption in mining and manufacturing, except for manufacturing use of metallurgical coal. Electric utilities have long been the major consumer of coal, and during this period, their share of coal consumption increased from 54 to 68 percent. The increased share reflects increased generation of electrical energy and some shifts from use of oil and natural gas as boiler fuel.

TABLE 23.—*Production and consumption of bituminous coal and lignite*

[In millions of tons]

	Production	Consumption					
		Electric power utilities	Coke ovens	Other manufacturing and mining	Exports	Retail dealers deliveries	Total
Year:							
1977 [1]	700.0	480.0	90.0	65.0	62.5	6.0	703.5
1976 [1]	665.0	442.0	85.0	64.5	60.0	5.5	657.0
1975	648.4	403.2	83.2	62.5	65.6	5.7	620.2
1974	603.4	390.1	89.7	64.1	59.9	8.8	612.2
1973	591.7	386.9	93.6	67.2	52.9	8.2	608.8
1972	595.4	348.5	87.3	72.0	56.0	8.8	572.6
1971	552.2	326.3	82.8	74.2	56.6	11.4	551.3
1970	602.9	318.9	96.0	88.3	70.9	12.1	586.2
1969	560.5	308.5	92.9	90.9	56.2	14.7	563.2
1968	545.2	294.7	90.8	97.7	50.6	15.2	549.0

[1] Estimated.

Source: Department of Commerce.

Coal production generally is described as being demand limited, that is, the level of production is determined by the demand for it, as illustrated by the increases in production and consumption since 1968. Consumers of large amounts of coal, primarily electric utilities and some industrial firms, tend to sign contracts directly with mine owners for all or a specific portion of the mine's output. Several years of lead-time are necessary between the decision to open a mine and the start of production. A new surface mine usually can be brought into production in one to three years in contrast with a new underground mine for which four to five years usually are needed before the start of production. Irrespective of the site and the type of mining operation, the process of opening a new mine includes building roads for trucks and roadbeds for railroad cars as well as other types of construction related to the process of transporting the coal from the mine to the consumer.

Coal is transported from the mine to the consumer primarily by train. In 1974, as shown in table 24, railroads carried 66 percent of the coal that moved between mines and consumers. Water transportation and trucks, respectively, carried 11 percent of the total. The rest was carried in miscellaneous forms, including a small amount by slurry pipelines. Nearly 40 percent of the coal carried by railroads is carried by unit trains.

TABLE 24.—*Bituminous coal and lignite loaded for shipment by railroads and waterways in the United States, in 1974, as reported by mineowners*

[In millions of short tons]

Type of transportation	Amount	Percent
Railroad	397.2	65.8
Waterways	67.8	11.2
Truck	66.4	11.0
Unspecified: Directly to electric utilities adjacent to or near coal mine	66.6	11.0
All others	5.5	.9
Total	603.4	100.0

Source: U.S Bureau of Mines, Minerals Yearbook, 1974, pp. 389–390.

Note: Detail may not add to totals due to rounding.

The interval between the decision to open a new coal mine and shipment of the initial load of consumable coal usually is long enough for manufacture of the additional carriers needed, including construction of new railroad roadbeds. In the event there is a substantial increase in openings of new mines and increased production from existing mines, all purchasers of transportation equipment may not be able to receive delivery when the equipment is needed. The accuracy of this statement depends upon how much new equipment is ordered in a short period of time and how quickly production can be increased in the transportation equipment industries.

The existing railroad lines may be extensive enough to carry the coal where it is needed. If they are not and new railroad lines must be put in place, there may be further delay in the delivery of coal by rail to those areas. More flexibility exists with respect to freight cars, because more efficient use of the cars, especially shorter turnaround time, could offset a temporary shortage in the number of cars. Deterioration of roadbeds in some sections in the country is being corrected under a program which was begun in April 1977 under the Railroad Revitalization and Regulatory Reform Act of 1976.

Coal slurry pipelines can move coal efficiently between fixed terminals over a fixed route. The pipeline moves a water and coal mixture, and by its nature places relatively large, additional demand on the water supply in the area where the coal is mined. Serious problems and resistance to slurry pipelines may arise in those areas where there is not a copious flow of water. The pipelines require substantial, initial capital costs, but the operating costs are relatively low. Presently, start on construction of the pipelines has been delayed because legal complications have arisen over the rights-of-way.

Expansion of Mining Capacity

The proposed national energy programs, as presented by the administration, call for continued, substantial increases in coal consumption by electric utilities that will result from continuation of the pattern that began after 1973—a substantial shift from oil and natural gas to coal, nuclear fuel or other sources. In part, the ability of the coal industry to provide sufficient output is demonstrated by the production increases in the past several years. Even more rapid increases may be necessary in the future as the electric utility industry is shifted completely from reliance on oil and gas. Coal production in 1977 is estimated to be 700 million tons, an increase of 35 million tons (or 5 percent) over 1976. Projections made in 1976 as a result of surveys by the National Coal Association and FEA (shown below in table 25) indicate current plans to expand coal production capacity by about 440 million tons by 1985 over 1976 levels. The net gain in current productive capacity will be reduced by about 140 million tons by 1985 as some producing mines are depleted. These expansion plans were developed in anticipation that potential difficulties with the labor force and transportation systems would not seriously restrict deliveries of coal to consumers.

TABLE 25.—*Coal mine expansion plans*

[In millions of tons of added capacity]

	1976	1977–79	1980–82	1983–85	Total	Total minus depletion
NATIONAL COAL ASSOCIATION SURVEY—AUGUST 1976						
Total	57.58	219.77	149.66	72.88	499.87	339.87
Steam	45.54	173.83	130.64	65.15	415.15	NA
Metallurgical	12.04	45.94	19.02	7.73	84.72	NA
Surface	30.06	134.70	94.90	49.10	308.76	NA
Underground	27.52	85.07	54.76	23.78	191.11	NA
East	30.62	98.34	63.13	32.48	224.60	64.60
West	26.96	121.41	86.50	40.40	275.27	275.27
FEDERAL ENERGY ADMINISTRATION STUDY—MAY 1976						
Total	64.20	220.05	162.25	56.50	503.00	366.00

NA—Not available.

Source: Standard and Poor's Industry Survey, Feb. 3, 1977.

Another possible restraint on the growth in coal production is the available labor force. During the years when coal production declined, unemployed miners moved to other industries, and there was litttle if any inflow of new people into the mines. The experienced labor force for coal mining may not be adequate at the moment. The availability of jobs in mining with substantial uemployment throughout the country may encourage workers with some experience to return to coal mining. There may be a sufficient flexibility in the labor force to meet immediate expension of the coal output. Thereafter, it will depend upon the relative advantages of coal mining over other occupations in terms of pay, fringe benefits and working conditions.

Research and Development

Mining research and development has several objectives. Increasing mining efficiency may be accomplished by increasing the reliability of presently used equipment and by developing reliable automatic and remote control techniques and equipment. Additional sources for increased efficiency include raising the percentage of coal recovered from a mine and improving techniques for mining coal deposits efficiently and safely at greater depths. Some rich deposits of coal are found in steeply pitched seams from which recovery rates are relatively low with present techniques and equipment.

Both deep and strip mining encounter environmental problems for which solutions must be sought. Associated with underground mining are subsidence of surface land and water contamination—usually acids. Restoration of the land surface and contours is a major environmental objective for strip mining. The Bureau of Mines and others are trying to develop methods to integrate environmental protection with efficient mining techniques.

Methane gas is found with coal and may be derived from it. Techniques are being developed to remove methane from coal seams before they are mined. After this gas is recovered, it may be sold to utilities or for industrial use. Recovery of substantial amounts of methane before mining also would diminish a major hazard in deep mining.

Synthetic methane may be produced from bituminous coal. It is possible to produce such gas with a high or a low Btu content. Techniques for producing a low Btu gas were used extensively before natural gas was available abundantly. The engineering knowledge of the old process supplemented with technological developments in the past several decades should result in production of large amounts of synthetic gas in the future. (See section IX below for an estimate of the size of its contribution by the year 2000.) Costs of manufacturing gas yields synthetic gas at a price too high to be competitive with current prices of natural gas. Increasing prices of natural gas and further improvement in the manufacturing techniques for synthetic gas, especially developments for producing higher Btu gas, should make synthetic gas available as a substitute for natural gas at a competitive price. If restrictions on the use of natural gas are enacted in the future, the demand for synthetic gas should assure more rapid growth in its manufacture.

Most techniques for making synthetic gas involve an above the ground process which requires first mining the coal and then transporting it to the manufacturing. Several current ERDA experiments are directed at burning lignite and sub-bituminous coal—both low BTU and permeable coals—underground. A low Btu gas is produced, but because the process involves relatively less capital investment, its price may be competitive with the administration's price-plus-tax targets for natural gas used as boiler fuel. This process, however, develops the same environmental problems, as does deep coal mining, with land subsidence and water contamination. In addition, fire control may involve other hazards.

Coal Prices and Profits

Coal prices, per million Btu, have ranged near 50 percent of the equivalent oil price and 10 to 20 percent above the equivalent gas price. Coal prices are unregulated and basically responsive to the demand for coal. Electric utilities, the dominant consumers of coal, tend to sign long-term contracts for a mine's total output. The contract price usually reflects the current market price when the contract was signed, with provisions for a pass-through of higher operating costs and, occasionally some protection of profit margins. Steam coal spot prices ranged between $10 and $20 a ton in mid-1976 have risen since then. A rising trend should continue through 1977 as consumers build inventories as a hedge against a coal strike late in 1977. Subsequent price increases will be affected strongly by prices of oil and gas, including taxes, which consumers will be paying.

For most major coal producers, 1977 may bring only a modest earnings recovery, following a decline in profits in 1976. Wildcat strikes are likely to flare up around midyear in attempts to influence union elections, and the expiration of the labor contract in December could bring an official strike during the last weeks of the year. Both types of strikes could cut production by about 50 million tons and thus limit the growth in profits. The level of output, however, should be sufficient to meet the needs of consumers.

Ownership Interests

Generally, domestic coal mines are owned by corporations primarily involved in other economic activities. The table of selected owners and producers of coal (table 26, reproduced from a Standard and Poor's industry survey) shows one coal company (North American Coal) among the 10 largest steam coal producers in 1975; two of the 10 were electric utility systems (American Electric Power and Pacific Power and Light).

Table 27 summarizes coal reserves held by 150 companies. Companies also are classified by level of coal production in 1975 and by their primary economic activity. Seventy of the companies are primarily coal producers, but 44 of them produced nothing or less than 100,000 tons in 1975. Oil and gas companies and electric utilities were the next two largest types of holders of coal reserves. Thirty-nine of the mines produced 2 million or more tons; 8 were coal companies, 9 were in oil and gas, and 6 in each of electric utilities and steel. The 9 oil and gas companies held the largest reserves—28 billion tons; the 8 coal companies and 3 companies in metals other than steels each held reserves of 10 billion tons, and electric utility and steel companies held between 5 and 6 million tons each.

TABLE 26.—*Selected owners and producers of coal*

Company	Recoverable coal reserves (billion tons)	1975 coal production			Percent of 1975 earnings from coal
		Total (million tons)	Percent steam	Percent metallurgical	
Continental Oil	13.7	49.2	88	12	42.0
Burlington Northern	12.0	5.6	100	0	6.0
Union Pacific	10.0	[1] 6.6	100	0	3.0
Kennecott Copper [2]	9.0	71.9	100	0	100.0
Exxon Corp	8.4	2.9	100	0	([3])
North American Coal	4.8	9.6	93	0	100.0
Occidental Petroleum	3.4	19.4	70	30	59.0
American Electric Power	3.3	8.3	100	0	0
AMAX, Inc	3.1	21.8	100	0	37.0
Kerr McGee Corp	2.8	0	----	----	0
United States Steel	2.7	17.1	0	100	([3])
Sun Oil Co	2.3	0	----	----	0
Atlantic Richfield	2.2	0	----	----	0
Utah International	1.8	20.8	30	70	90.0

Gulf Oil	1.75	7.3	100	0	(3)
Pacific Power & Light	1.73	(4)	100	0	8.8
Texaco, Inc	1.65	0			0
Pittston Co	1.5	18.6	25	75	92.0
Eastern Gas & Fuel	1.1	7.8	44	56	61.0
Montana Power Co	1.1	6.4	100	0	[5] 15–20.0
Houston Natural Gas	1.0	4.2	100	0	10.0
Westmoreland Coal	.85	7.9	45	55	100.0
Standard Oil of Ohio	.84	9.3	75	25	25.0
Bethlehem Steel	.45	13.4	0	100	0
St. Joe Minerals	.38	9.2	67	33	55.0
Carbon Industries	.12	2.7	34	66	100.0
Kaneb Services	.09	1.6	100	0	45.0
Falcon Seaboard	.07	4.5	100	0	83.0

[1] From properties in which it has interests.
[2] Kennecott is under FTC orders to divest its coal holdings.
[3] Minor.
[4] Had interests of 50 percent or more in 18,000,000 tons of 1975 production.
[5] Approximate.

Source: Data assembled from company reports by Standard and Poor for Industry Survey, Sept. 2, 1976, sec. 2, p. 561.

TABLE 27.—*Coal Reserves Held by 150 Largest Holders*

[Production and reserves in millions of tons]

Production in 1975	Primary interest of reserves holder: Coal		Railroad		Oil and gas		Electric utilities		Steel	
	Number	Reserves	Number	Reserves	Number	Reserves	Number	Reserves	Number	Reserve
1. More than 3	6	9,666			8	21,472	5	5,670	3	4,625
2. 2 to 3	2	350			1	7,000	1	401	3	720
3. 1 to 2							1	160		
4. 0.7 to 1	2	190					1	188		
5. 0.5 to 0.7	3	255								
6. 0.4 to 0.5	2	37					1	50		
7. 0.4 to 0.4	2	430	1	36	2	450				
8. 0.2 to 0.3	3	65								
9. 0.1 to 0.2	6	181								
10. 0 to 0.1	29	4,050	1	276	1	1,500	2	170		
11. 0	15	4,556	7	23,512	8	7,428	4	957	1	370
Total	70	19,780	9	23,824	20	37,850	15	7,596	7	5,715
Percent of total reserves		17.7		21.3		33.9		6.8		5.1

	Other metals		Chemical		Other		Totals	
	Number	Reserves	Number	Reserves	Number	Reserves	Number	Reserves
1. More than 3	2	10, 000			6	3, 656	30	55, 089
2. 2 to 3	1	60	1	255			9	8, 786
3. 1 to 2			1	125	1	42	3	327
4. 0.7 to 1	1	265					4	643
5. 0.5 to 0.7					1	160	4	355
6. 0.4 to 0.5					1	200	4	287
7. 0.3 to 0.4							5	916
8. 0.2 to 0.3					2	30	5	95
9. 0.1 to 0.2					2	250	8	431
10. 0 to 0.1	1	323			5	719	39	7, 038
11. 0	1	350	1	203	2	260	39	37, 636
Total	6	10, 998	3	583	20	5, 257	150	111, 603
Percent of total reserves		9. 9		. 5		4. 7		

Source: *Keystone Coal Industry Manual 1976 Edition*, Major Coal Producers by Size of Output, pp. 721–724, The Coal reserve picture—Estimated Tonnages Held by Individual Firms, pp. 735–737, Ownership of Coal Producing Companies, p. 738–739.

VII. NUCLEAR ENERGY

Since the 1950's, the United States has encouraged the use of nuclear energy as a long-term replacement for fossil fuels to generate electricity. Through the Atomic Energy Commission and its successor, the Nuclear Regulatory Commission, research and development on nuclear power has continued for 25 years. The United States is now in its 18th year of commercial nuclear power production.

In a nuclear power plant, the nuclear fuel core replaces fossil fuel in the generation of steam which in turn drives turbines which generate electricity. A nuclear fuel core contains uranium, fuel which has been enriched in its fissionable Uranium–235 (U–235)[1] content. When U–235 is bombarded by neutrons, the uranium atoms release energy in the form of heat plus additional neutrons which sustain the nuclear reaction. The heat is transferred to the primary coolant, which can be boiling water, pressurized sub-cooled water, gas or liquid metal. The resulting steam turns a turbine generator which in turn produces electricity.

Types of Reactors

There are three main types of reactors in the United States: (1) light water reactors, (2) gas cooled reactors, and (3) the developing liquid-metal fast breeder reactors.

(1) *Light water reactors.*—Light water reactors are fueled by enriched uranium dioxide (UO_2). Their name derives from the fact that ordinary water is used to cool the core, and in so doing generates steam which drives a turbine generator. The water may be either boiling or pressurized in its uses as a coolant.

(2) *Gas cooled reactors.*—Gas cooled reactors are fueled by U–235 in the initial reactor core and thorium–235, which is converted to uranium–232$_1$ in subsequent cores. High pressure helium gas is used as the coolant. Because of the high pressure and temperature with which these reactors operate, the gas cooled reactor has a net thermal operating efficiency of nearly 40 percent.

(3) *Liquid metal fast breeder reactor.*—This type of reactor produces more nuclear fuel than it consumes. A fast breeder reactor converts nonfissionable (and abundant) U–238 to fissionable plutonium-239. For the past 20 years, the AEC has been conducting studies, research and development on the breeder concept.

Use of Nuclear Energy for Electricity Generation

The importance of nuclear power for domestic electricity supply has grown markedly in the past several years. In 1973, nuclear fueled electricity constituted 4.5 percent of domestic electricity supply. In 1974, it rose to 6 percent; in 1975 it averaged 9.0 percent, and it averaged 9.3 percent in 1976. In January 1977, a period of unusually cold

[1] The term U–235 means uranium with an atomic weight of 235. The number 235 refers to a standard unit of weight in chemistry and physics.

weather and high electricity demand, nuclear power plants generated 11.3 percent of all U.S. electricity.

Table 28 displays the status of nuclear power plants as of the end of 1976. There are currently 62 light water reactors (24 boiling water reactors and 38 pressurized water reactors) and 1 high temperature gas cooled reactor in commercial operation.

The United States currently has substantially more nuclear generating capacity than other major non-Communist countries. (See table 29). In 1976, the United States had 45 megawatts of installed nuclear capacity compared to 7.3 megawatts in Great Britain or 7.4 megawatts in Japan. However, until January 1977, the capacity utilization, affected in part by technical reliability, has been lower in the United States (56 percent) than in Great Britain (64 percent) or Canada (85 percent).

TABLE 28.—*Nuclear powerplant status*

Status	Light water reactor types		Other [3]	Total reactors	Total capacity in net megawatts
	BWR [1]	PWR [2]			
Operating [4]	24	38	1	63	46
Construction permits:					
Greater than or equal to 2-percent complete [5]	16	39		55	58
Less than 2-percent complete	6	12		18	19
Under construction permit review [6]	19	41	4	64	72
Ordered	3	13		16	18
Announced			19	19	23
Total	68	143	24	235	236

[1] Boiling water reactor.
[2] Pressurized water reactor.
[3] Including 1 high-temperature gas-cooled reactor (HTGR), 1 liquid metal fast breeder reactor (LMFBR), and 22 reactors for which no design has been specified.
[4] Not including 2 ERDA-owned reactors with a combined capacity of 870MWe.
[5] Including 2 BWR units with limited work authorizations (LWA) for initial project construction pending final safety review and issuance of construction permit.
[6] Including 18 reactors with an LWA or exemption, less than 2-percent complete.

TABLE 29.—*Nuclear power generation by major non-Communist countries, January 1977* [1]

Country	Number of reactors	Capacity (January 1977) (000's of megawatts)	Generation (January 1977) (000's of megawatts)	Generation of electricity — Percent of design capacity — January 1977	Year [2] 1974	Year [2] 1975	Year [2] 1976
Canada	7	3. 9	2. 0	67	74	64	85
Federal Republic of Germany	10	6. 4	3. 4	71	57	72	68
France	10	3. 1	1. 6	69	57	68	58
Great Britain	[3] 26	7. 3	3. 1	62	61	57	64
India	3	. 6	. 3	64	55	46	58
Italy	3	. 6	. 4	83	61	69	69
Japan	13	7. 4	1. 9	35.	61	36	57
Spain	3	1. 1	. 6	74	75	77	77
Sweden	5	3. 3	1. 9	77	20	44	55
Switzerland	3	1. 1	. 7	100	76	84	86
United States	60	44. 1	23. 0	70	57	60	56

[1] Includes only operational units, i.e., those which have generated electricity during, or prior to, the current month.

[2] Averages are computed for those units in operation on Jan. 1 of each year.

[3] Information for Calder Ham (240 megawatts) and Windscale (32 megawatts) not available; figures are for 4-week period.

Source: *Nucleonics Week.*

In the past four years, concern over waste disposal, safety, reprocessing, capital costs, and uncertainties over the price and availability of uranium have led utilities to delay their orders for new reactors. In 1973, 34 reactors were ordered, in 1974, 26 reactors were ordered, in 1975, 4 reactors were ordered, and in 1976, 1 reactor was ordered.

The Nuclear Fuel Cycle

To understand the current issues surrounding nuclear fueled electricity, it is helpful to understand the nuclear fuel cycle.

Uranium ore is found in pitch blend ore. The ore is extracted from sandstone deposits by open pit or deep mining. Current grades of ore being mined contain 4–5 pounds of uranium oxide per ton of ore. A typical 1,000 megawatt electric power plant thus requires 125,000 tons of ore per year.

The ore is then purified into another uranium oxide generally called "yellowcake." About 125,000 tons of ore must be milled to obtain 240 tons of yellowcake. Uranium prices are usually quoted in terms of the price of yellowcake. The price of yellowcake has skyrocketed from $10 per pound 18 months ago to highs of $40 per pound today. The current difficulties of Westinghouse Corporation are related to this fourfold increase in raw material prices as they have outstanding contracts to provide enriched uranium which a yellowcake price of $40 per pound makes uneconomic.

The yellowcake is converted to a fluoride of uranium, UF_6, which is solid at room temperature. At this point, the UF_6 contains only .7 percent of the fission isotope U–235 (and 99.3 percent of U–238); U–235 provides the energy earlier described. There are two ways to raise the U–235 content of the fluoride of uranium—through diffusion or centrifuge technology. Diffusion technology makes the flouride gaseous and separates the U–235 from the U–238 by a series of membranes. Substantial electricity is needed to drive the compressors which force the UF_6 through the membranes, and substantial water is needed to reduce the heat generated by the process. Centrifuge technology spins the UF_6 at high speeds so that U–235 is separated from U–238 by their weight differential. This second technology is still in the developmental stage, while diffusion has been viable for some time.

The enriched UF_6 is then converted into a solid uranium oxide, UO_2, and the solid cut into ½-inch pellets which are assembled into, or clad in, reactor rods which go into the core of the reactor.

In the light water reactor, most of the heat comes from the fissioning of U–235. Fission occurs when unstable isotopes of the element split into atoms of a lower atomic weight. The process is accompanied by the release of neutrons and a large amount of energy. Some atoms of plutonium-239 (Pu-239) are also formed in the reactor when an atom of U–238 captures a neutron. For each gram of U–235 consumed as fuel, about 0.6 grams of plutonium is formed. Generally, over one-half the plutonium which is formed undergoes fission and releases heat in the core, contributing significantly to the energy produced in the powerplant.

Each year, about one-fourth to one-third of the reactor rods must be replaced because the U–235 content is too low to sustain fission. The spent rods are first kept under water for 5–6 months to allow their radioactivity level to decrease. Then, reprocessing begins in which the uranium and plutonium are separated from each other.

In the separation process, the uranium and plutonium must be separated from the cladding or rods. The latter becomes waste material which is highly radioactive. The separated uranium is sent back to a fuel processing plant where it is enriched as earlier described. The plutonium is either stored or used as fuel itself.

Issues in Nuclear Technology

Plutonium

Plutonium is a byproduct of either the light water reactor or the breeder reactor. Because plutonium is used to make nuclear weapons (30 pounds of plutonium—about half the annual byproduct of a current light water reactor—is sufficient to make a substantial nuclear weapon), there is a serious concern that the security of the nuclear fuel cycle be maintained. Because the breeder reactor generates more plutonium than it consumes, the use of this technology, as compared to conventional light water reactor technology, substantially compounds the security problem. In April of this year, the administration reversed previous policy and stopped development on several breeder reactors. However, this decision is being actively reviewed now by congressional committees.

Waste management

Any nuclear technology creates radiation hazards and problems of waste management. Because radioactive decay is extremely slow, such materials must be stored fcr long periods of time. While a variety of technologies are available to do this, many, such as underground storage, require continuous surveillance, since there is a constant risk of ground water contamination. To a large extent, public criticism of nuclear power has shifted from reactor safety to radioactive waste.

Currently, ERDA is conducting field investigations and analyses in 36 States to determine the suitability of underground structure for waste dispostal. The Environmental Protection Agency and Council on Environmental Quality have repeatedly expressed concern about waste management problems.

Availability of uranium

The recent quadrupling in the price of yellowcake coupled with a decision not to pursue the breeder reactor means that there will be increased demand for uranium and therefore higher prices. Recent court proceedings have contained evidence to suggest that international uranium producers have acted as a cartel since 1972 to fix world market prices.

Estimates of U.S. uranium reserves vary considerably. Table 30 displays July 1976 ERDA estimates of domestic uranium oxide reserves. The forward cost represents the cost of producing additional yellowcake with existing facilities. An average thousand megawatt reactor uses 5,000 tons of yellowcake over its 30-year life, or 200 tons a year. Current total annual reactor consumption is 45,000 tons a year. Known reserves represent 17 years supply of yellowcake at current consumption rates. If probable reserves are added to known reserves at the $30 forward cost, there are 41 years of supply. These supply figures, of course, assume a constant consumption level. In the event consumption were, say, to double immediately to 90,000 tons a year, the supply estimates would be divided in half.

TABLE 30.—*Reserves of uranium oxide yellowcake*

[In thousands of tons]

Forward cost [1] (1975 dollars a pound)	Reserves	Potential resources: Probable	Possible	Specula-tive	Total
$10	270	440	420	145	1, 275
$15	430	655	675	290	2, 050
$30	640	1, 060	1, 270	590	3, 560
	[2] 140				140
Total supply	780	1, 060	1, 270	590	3, 700
Cumulative number years' supply [3]	17. 3	40. 9	69. 1	82. 2	82. 2

[1] Forward costs are those costs incurred after the geological investigation, land aquisition, and exploration have been completed, and therefore do not represent prices at which uranium oxide will be marketed.

[2] By-product of phosphate and copper production that becomes available independent of forward costs.

[3] Assumes 45,000 tons a year consumption.

Source: ERDA, July 1976.

VIII. HYDROELECTRIC POWER

In the 1930's and 1940's, hydroelectric plants supplied about 30 percent of the electric energy produced in the United States. Today, this percentage has dropped to about 15. Fewer prime sites and concern about the environmental impact of dam projects have been largely responsible for this relative decline. Advantages of conventional hydroelectric projects are that they do not consume fuel, are nonpolluting, are relatively reliable, and are especially suited to providing peak and reserve capacity for electrical systems. In addition, hydroelectric facilities often provide recreation, water supply and flood control benefits.

Recent Trends in Hydroelectric Power Generation

As of January 1, 1976, the total capacity of developed hydroelectric facilities in the United States (including Alaska and Hawaii) amounted to 57,000 megawatts (Mwe) of capacity. Average annual generation from this capacity is approximately 271 billion kilowatt-hours. Actual production in any year may deviate considerably from this average because of variability in water flows. For example, actual hydroelectric production in 1975 was about 300 billion kilowatt-hours because of higher than average water flows in that year.

As shown in table 31, hydroelectric capacity has grown substantially in recent years, although the rate of growth is declining. Thus, the percentage of electricity generated from hydroelectric sources is likely to continue to fall.

TABLE 31.—*Trend in developed conventional hydroelectric capacity*

Year as of January 1:	*Developed capacity (millions of kilowatts)*
1921	3.7
1925	5.0
1930	7.8
1935	9.3
1940	11.0
1945	14.6
1950	17.7
1953	21.4
1957	26.6
1960	31.9
1964	40.2
1968	45.8
1972	53.4
1976	57.0

Source: Federal Power Commission.

Supply Limitations

The most important factor limiting the supply of hydroelectric power is the limitation on technically feasible sites. However, there are also important environmental, social and economic factors affecting potential future construction.

The most serious environmental problems result from the impoundment of water, i.e., the formation of reservoirs and lakes, behind the dam. Construction of a new hydroelectric facility involves a permanent loss of land which may be prime farmland, may contain mineral deposits, or may be a wildlife habitat and contain recreational opportunities on free-flowing streams. The recent controversy concerning a proposed facility on the New River in North Carolina, now precluded by legislation signed in 1976, illustrates this point. In addition, relocation of houses, communities and industries is often necessary as a result of the land loss.

River conditions downstream often change as the result of new hydroelectric construction. Erosion during construction may contribute to pollution. Variation in the amount of water released from the reservoir, corresponding to daily, weekly and seasonal patterns in electricity demand, can change stream temperatures adversely affecting fish. Dams also act as barriers to the movement of fish and may interfere with their reproductive activities unless special precautions are taken.

Hydroelectric Potential

The Federal Power Commission maintains a detailed inventory of potential hydroelectric capacity. Based on estimates of technical feasibility only, the FPC estimates that total undeveloped capacity is about 114 million kilowatts which could provide average annual generation of 404 billion kilowatt-hours. Thus, hydroelectric power output could be more than doubled if this capacity were developed. The FPC emphasizes, however, that this is an upper limit, since many of the sites in their inventory have undergone very little feasibility analysis.

There is considerable regional diversity in this potential for expansion, however. Over one-third of the potential annual output would be located in Alaska, far from the main sources of demand. Almost half the remaining potential is located in the Pacific States, while relatively little is located in the Midwest.

Much of this theoretical capacity will probably never be developed because of environmental and economic constraints. For example, recent legislation, including the Wild and Scenic Rivers Act of 1968, has specifically precluded development of certain projects which were once listed in the FPC's inventory but are not included in the above figures. Other potential projects which could provide 11 million kilowatts of capacity and an annual average of 30 billion kilowatt-hours are in areas which are being considered for similar action in the future. In addition, many of the projects which the FPC considers technically feasible are so small that they probably are not economically feasible; many small plants are currently being abandoned. Thus, the amount of capacity ultimately developed is likely to be much less than the figures quoted above. Future increases in oil, gas and coal prices, however, could make some of these projects feasible, and thus change the forecasts of probable development of capacity.

Projections for Hydroelectric Production

Only a small fraction of the potential hydroelectric capacity just described is likely to be developed in the next 20 years. The relevant figures are shown in table 32. The facilities under construction on January 1, 1976, are likely to be generating power by 1980, while those for some preliminary planning activity have taken place, such as Federal authorization or preliminary license application, will probably become operational between 1980 and 1995. This development is likely to be concentrated in Northwestern States. These figures would imply that hydroelectric power would drop to 11 percent of the total by 1980 and 9 percent of the total by 1985.

It should be emphasized that these projections are subject to a great margin of error. For example, rising prices of oil and gas, and thus the electricity derived from them, might retard the abandonment of old projects and accelerate the development of new ones. New turbine technology allowing power to be efficiently generated from shallow lakes may also increase the economic feasibility of certain locations. Any reduction in the average 20-year time span which is required for the completion of a project would also reduce costs. Also, some have argued that the FPC has vastly underestimated the potential for new hydroelectric power which could result from expansion of existing facilities.

TABLE 32.—*Existing and projected hydroelectric power capacity and production in the United States*

	Installed capacity (million kilowatts)	Average annual production (billion kilo-watt-hours)
Developed capacity as of Jan. 1, 1976	57	271
Under construction as of Jan. 1, 1976 (likely to be completed by 1980)	8	17
Projected for completion by 1985	8	17
Other projected (preliminary planning has begun)—likely to be developed by 1995	6	15
Total capacity likely to be developed by 1995	79	320
Total ultimate capacity:		
Not including plants barred by law or those under environmental study	160	645
Not including plants barred by law	171	675

Source: Federal Power Commission

IX. ENERGY SUPPLY WITH CONVENTIONAL AND WITH NEW TECHNOLOGY UNDER REFERENCE AND ACCELERATED FORECASTS

Energy Supply-Reference Forecast

The purpose of this section is to show the approximate contribution to energy supply that can be expected from new technology during the period 1975 to 2000, under both the "Reference" (or base case) and "Accelerated" forecasts. The Reference case contains estimates that the Energy Research and Development Administration (ERDA) and the Federal Energy Administration (FEA) have agreed are reasonable, if no new government incentives are enacted. The Accelerated case contains FEA estimates of future events under the assumption of major government interventions. (See below for detail on the assumptions and methods.)

The energy supply reference forecast shown in table 33 traces the pattern of energy supplies from 1975 to 1990. Total energy produced is forecast to increase by about one-half between 1975 and 1990. The major changes in the source of energy over this period is the decline in the importance of domestic oil from 29 to 21 percent of the total, a decrease of 28 percent, and the comparable decline in the share of gas from 28 to 19 percent, a decline of 32 percent. These sources represent about the same absolute amount of energy in 1990 as in 1975, but the increase in other sources is expected to decrease their relative importance. The major increase is coal production which is expected to increase absolutely by 75 percent and from 18 to 23 percent of total energy over the period. Oil imports are also expected to increase by 75 percent with their relative importance increasing from 18 to 21 percent.

TABLE 33.—*U.S. energy supply-reference forecast, 1975–85 (percentage distribution of energy sources)*

	1975	1980	1985	1990
Oil imports (net)	18	19	18	21
Domestic oil (including NGL) [1]	29	28	26	21
Gas (dry; including imports)	28	23	21	19
Coal	18	23	23	23
Nuclear	3	4	8	10
Solar, hydro, and geothermal	5	4	5	6
Total all energy (percent)	100	100	100	100
Total all energy (quadrillion Btu's) [2]	71	83	92	104
Total all energy (millions of barrels of oil per day)	35.5	41.5	46	52

[1] Natural gas liquids.
[2] 1 million barrels of oil per day equals 2 quads (quadrillion Btu's) and 1 trillion cubic feet of natural gas equals 1 quad.

Source: Federal Energy Administration.

New Technology—Reference Forecast

New technology in the Reference Forecast (no new programs) is not expected to increase its share of energy production significantly between 1985 and the year 2000. Table 34 provides a way of putting the importance of new technology in perspective. Over the period in question, the share accounted for by imported oil and gas is expected to decline from 20 percent to about 14 percent, a decline of 6 percentage points. This is offset by an increase in the share provided by nuclear power from 8 to 15 percent, an increase of 7 percentage points. The share of conventional nonnuclear power is expected to decline by 5 percentage points, from 71 to 66 percent. This decline is nearly offset by the increased energy from new technology, a 4-percentage point increase from roughly one to 4.7 percent. The composition of this 4.7 percent total is .7 percent for synthetics, 1.3 for solar, 1.7 for geothermal and 1.0 for breeder reactors.

TABLE 34.—*Summary, new technology reference case energy forecasts, 1985–2000 (percentage distribution of energy sources)*

Energy source	1985	1990	2000
Conventional (nonnuclear domestic)	71.2	64.1	66.5
Nuclear	8.0	10.0	15.0
Imported oil and gas	20.2	23.9	13.8
Total new technologies	.7	1.9	4.7
Synthetics	.2	.5	.7
Solar	.1	.8	1.3
Geothermal	.3	.7	1.7
Breeder reactor			1.0
Total all energy (percent)	100	100	100
Total all energy (quadrillion Btu's)	92	104	144
Total all energy (millions of barrels of oil per day)	46	52	72

Source: Federal Energy Administration.

Even though the energy from new technology is expected to increase more than 10-fold, from .6 to about 6.7 quadrillion Btu's between 1985 and 2000, it still will not represent a large share of total energy supply under the Reference forecast.

New Technology—Accelerated Forecast

With an accelerated program of Federal financial support (described in more detail below) the contribution of new technologies to our energy supply can be expected to double by the year 2000, from 4.7 percent to about 10 percent. This represents an increase from the 6.7 quadrillion Btu's of the reference case to about 14 quadrillion Btu's in the accelerated case or from the energy equivalent of about 3.8 million barrels of oil per day to about 7 million. As table 35 shows, almost all of the increase is in solar (from 1.3 percent to 4.4 percent) and geothermal (from 1.7 to 3.4 percent).

TABLE 35.—*Summary, new technology accelerated case energy forecasts, 1985–2000 (percentage distribution of energy sources)*

Energy source	1985	1990	2000
Conventional (domestic)	77.7	71.0	76.1
Imported oil and gas	20.1	23.9	13.8
Total new technologies	2.2	5.1	10.1
Synthetics	.8	1.4	1.3
Solar	.8	2.4	4.4
Geothermal	.6	1.3	3.4
Breeder reactor			1.0
Total all energy (percent)	100	100	100
Total all energy (quadrillion Btu's)	92	104	144
Total all energy (millions of barrels of oil per day)	46	52	72

Source: Federal Energy Administration.

Description of FEA/ERDA Reference and Accelerated Supply Energy Forecasts

Overall economic assumptions

New technology energy supply forecasts were developed in the context of energy demands and prices generated by the ERDA modeling system. For short-term analyses (up to 1985) all ERDA models are consistent with FEA 1985 forecasts as developed by PIES (Project Independence Evaluation System) for the National Energy Outlook. Both ERDA and FEA use the Data Resources, Inc. (DRI) "Trend Long" forecast, which assumes real growth in GNP of 6.5 percent in 1976, 5.4 percent in 1977 and then staying relatively constant until the 1980's when it averages 3.2 percent for the ten-year period 1981–1990.

Real energy prices are assumed to increase as shown in Table 36, generally one percent a year. Natural gas price increases are artificially low due to the assumption of some continued degree of regulation. The real prices of energy resulting from these assumptions in dollars per million Btu's are shown in table 37.

TABLE 36. *ERDA best estimate forecast real price increase for selected energy forms*

Energy type	Annual rate of real price increase (percent)	
	1985–90	1990–2000
Domestic oil	1.0	2.0
Imported oil	1.0	2.0
Shale oil	.0	.5
Natural gas	1.5	1.0
Strip mined coal	.5	.5
Underground coal	1.0	1.0

TABLE 37.—*ERDA best estimate forecast wholesale real prices (1975 dollars) of selected energy forms* [1]

Energy type	Dollars per million Btu's		
	1985	1990	2000
Domestic oil	2.24	2.35	2.87
Imported oil	2.24	2.35	2.87
Shale oil	2.50	2.50	[2] 2.62
Natural gas	1.93	1.98	2.19
Nuclear fuel	.65	.70	.77
Strip mined coal	.61	.63	.66
Underground coal	.61	.64	.71
Syn crude	3.45	3.50	3.57
Hight Btu gas	3.54	3.61	3.65
Central station geothermal	10.28	10.28	10.16
Central station solar	13.14	13.14	13.00
Dispersed mode geothermal	2.75	2.75	2.75
Dispersed mode solar	14.02	13.24	11.69

[1] $2.54, $0.65, $0.28, and $1.60 per million Btu's for gasoline, distillate oil, residual oil, and kerosene, respectively should be added to wellhead costs to account for refining, transport and markup. $0.85, $0.51, and $0.22 per million Btu's for natural gas to the residential, commercial, industrial sectors respectively, should be added to wellhead costs to account for refining, transportation and markup. $0.32 and $0.13 per million Btu's should be added to mine month costs to account for processing, transport and markup.

[2] The price of shale falls below oil in 2000 primarily due to the lower rate of annual real price increase. The model, however, may only select shale up to a maximum amount of 2.8 quads due to assumptions concerning reasonable penetration rates.

Reference and accelerated case assumptions

Most Reference and Accelerated case assumptions were supported by studies that have been conducted in each energy area. A summary of some of the principal assumptions from these studies is presented below. The application of new energy technologies is at an early stage, and is subject to the effects of a rapidly growing research and development program. The results of this R and D program will greatly influence the rate at which some of the new technologies achieve commercial acceptance. The magnitude of the contribution of the new energy technologies, moreover, will be strongly influenced by actions taken by government—at the Federal, State, and local levels—to accelerate commercialization and to remove any social and institutional restrictions. Thus, the existing projections from these sources, although they are of the correct order of magnitude, are rough estimates.

Solar energy

For the Reference Case forecast it is assumed that the Federal Government takes no action with regard to solar energy beyond (1) the current research and development program conducted by the Energy Research and Development Administration, and (2) the loan guarantee and financial incentive demonstration programs authorized by the Energy Conservation and Production Act of 1976 (Public Law 94–385).

For this case, only solar heating and cooling are assumed to achieve appreciable production levels in 1985 and beyond. The first new commercial use of solar energy projected to reach significant production levels would be for hot water and space heating followed by space cooling. The life cycle costs of these systems will become increasingly competitive with fossil fuels between now and 1985. This will be particularly true for new buildings and multiple family dwellings.

The Accelerated Case Forecast is based on the assumption of an additional investment of government funds from now through 1985 of between 2 and 4 million dollars above the market cost of the equipment in the following areas:

Tax credits to consumers for installation of solar hot water and/or heating systems;

Substantial use of solar hot water and space heating by the Federal Government for the purpose of creating a substantial early market in order to help stimulate the industry;

A "wind seeding" project to provide a wind turbine generator to a number of utilities to accelerate familiarization.

Geothermal energy

For the Reference Case Forecast normal expansion at the Geysers in California through 1985 is assembled, followed by moderate expansion of that resource area and other, economic resource areas. No federal or state interventions that change the overall economics of generating electricity from geothermal source are assumed. It is also assumed that development will be relatively independent of world oil prices.

The Accelerated Case Forecasts are based on the assumption that the Federal Government will: (1) provide financial incentives for geothermal development; (2) conduct a successful research development, and demonstration program to provide technology to use much of the liquid-dominated hydrothermal resources; and (3) assist in removing or minimizing social and governmental restraints to geothermal development.

Synthetic fuels

Synthetic fuels offer an option between now and the end of the century to make use of some of the abundant U.S. reserves of coal and oil shale. Production of synthetic gas involves a chemical reaction between coal, oxygen and water which produces carbon monoxide, hydrogen gas and/or methane depending on the process used. Both low and high Btu gas can be produced. High Btu gas, containing mostly methane, has the advantage of being almost identical to natural gas, and can be used to supplement diminishing natural gas supplies. Low Btu gas could be used by electric utilities to generate electricity. Production costs for high Btu gas are approximately 20 percent greater than for low Btu gas. Synthetic liquid fuel (syncrude) can be produced from coal by hydrogeneration or indirectly by gasification to yield carbon monoxide and hydrogen which is then converted to liquids. Shale oil is produced by a process called retorting whereby mined shale rock is heated to about 900° Fahrenheit. This yields a heavy oil that can then be upgraded and refined to produce a typical line of oil refinery products. Commercial production of synthetic fuel requires lead times of from 10 to 15 years and involves large investments of capital, labor and resources. Some of the processes that could be employed to produce synthetic fuels from oil shale are estimated to be in the cost competitive range with the price of imported oil. However, there are numerous uncertainties that present a barrier to commercialization: (1) technical uncertainties associated with scaling plants up to commercial size and applying current pollution control technology; (2) uncertainties in cost projections, with estimates for any one process varying by as much as 50 percent; and (3) uncertainties in estimating the level and cost of public opposition because of environmental concerns.

In the Reference Case Forecast minimal supplies from synthetic fuels are assumed due to (1) their high, current relative cost of production; (2) large capital investments requiring lead times of from 10 to 15 years; (3) the uncertainty of U.S. future energy supplies, the world price of oil, and state and federal environmental legislation; and (4) the absence of Federal incentives. The Federal government is, however, assumed to continue to produce relatively small quantities of synthetic fuels for research and demonstration purposes. This projection is also based on the assumption that unlimited foreign oil supplies are permitted to enter the United States and that these suppplies are priced at levels sufficient to discourage private investment in synfuel plants for most of this century.

For the Accelerated Case projections a Federally-supported synthetic fuels program with a 1985 production target of 350,000 barrels of oil equivalent per day (about 0.7 quads per year) is assumed. Post 1985 total synthetic fuels production growth to the end of the century is assumed to be linear, with the addition of 0.7 quads each successive 5 year period. The projected growth of individual synthetics varies within this total as a result of the estimated relative distance of the technologies to commercial acceptability. This projection also assumes that after 1985, private industry accepts increasingly larger portions of the risk associated with investment in synthetic fuels production facilities as synthetic fuels become competitive in the marketplace.

In both sets of projections it is assumed that shale oil, of the various synthetic fuels, is closest to commercial production and that synthetic crude from coal is most removed from the onset of commercial production. No favorable assumptions were made regarding the likelihood that one of the second generation coal-liquefaction processes now under development will prove commercially acceptable. Such a development could significantly alter these projections.

Nuclear energy

The expansion of Light Water Fission Reactors is not usually considered a new technology. Only Breeder Reactors are considered as a new technology in the Reference Case forecast. No additional increased supply from this energy source is projected for the Accelerated Scenarios. Continued government support of research, development, and demonstration of the breeder with eventual commercialization in the 1990's is assumed for both the Reference and Accelerated Case. Approximately 30 breeder reactors of the 1,000 megawatt size are projected to become operational during the 1990's and be in commercial operation by the year 2000.

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