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POWER AND THE ENVIRONMENT— A POTENTIAL CRISIS IN ENERGY SUPPLY

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A POTENTIAL CRISIS IN ENERGY SUPPLY

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INTRODUCTION

As the decade of the 1970s begins, continual warnings are being issued regarding potential widespread electrical blackouts, while equally dire predictions are being made of the potential environmental hazards arising from the generation of electric power. The power curtailments and severe atmospheric conditions that occurred during the summer and early fall of 1970 may have been only a foretaste of serious problems that will confront the nation until a better balance can be achieved between the growing need for power and the demand that it be provided without detriment to the environment.

Several factors have contributed to the present situation in the contiguous United States. The rapid growth in the demand for electric power has required a doubling of output about every 10 years, yet there have been difficulties and delays in gaining approval for the construction and operation of new power plants designed to provide the additional power required. Shortages of fuels that can meet the increasingly stringent regulations made to protect air quality have compounded the problems.

Although the present energy crisis and related environmental problems may appear to have arisen quite suddenly, they have actually been in the making for many years, and their solution, too, will require time. Many solutions that offer the most immediate relief will be costly, and perhaps only temporary. If both the demand for power and the demand for environmental protection are to be met, extensive research and technical progress, requiring both large amounts of money and considerable time, will be needed.

ENERGY DEMAND AND SUPPLY

Since 1920 the annual gross consumption of energy from mineral fuels and hydropower in the United States has grown from 19,782 trillion Btu (1, p. 33)* to 65,753 trillion Btu (2, p. 5). During this period the percentages of energy produced from the various source materials have changed, as shown in table 1.

TABLE 1—TOTAL ENERGY PROVIDED BY FUELS AND WATER POWER IN THE UNITED STATES

Commodity	Percentage of total energy	
	1920	1969
Bituminous coal and lignite	67.4	20.2
Anthracite	11.0	0.4
Petroleum and natural gas liquids †	13.5	43.2
Natural gas	4.2	31.9
Hydroelectric power	3.9	4.1
Nuclear power	0.0	0.2
	100.0	100.0

† Includes imports.

Source: U. S. Bureau of Mines (1, p. 33; 2, p. 5).

While there has been a rapid growth in the use of fuels and energy for all purposes in the United States, the growth in use of electric power has been especially notable, as shown in table 2. Table 2 also shows that energy use not only has been growing but has been growing at an increasing rate. Fuel consumption for power generation increased 99.7 percent in the 10 years from 1959 to 1969, compared to 79.4 percent in the previous 12 years.

TABLE 2—CONSUMPTION OF ENERGY IN THE UNITED STATES IN 1947, 1959, AND 1969

Energy used	Trillion Btu			Percent increase	
	1947	1959	1969	1947-1959	1959-1969
In electric utility power generation	4,397	7,887	15,748	79.4	99.7
For all other uses	28,473	35,524	50,005	24.8	40.8
Totals	32,870	43,411	65,753	32.1	51.5

Source: U. S. Bureau of Mines (1, p. 33; 2, p. 5; 3, table 2; 4, p. 87).

Energy Sources for Power Generation

Within the United States electric power is generated by energy derived from fossil fuels (coal, gas, and oil), water power, and nuclear energy. Although

* Numbers refer to references listed at the end of the report.

TABLE 3—SOURCES OF ENERGY FOR ELECTRIC UTILITIES

Source	Energy consumed by utilities (%)		
	1947	1959	1969†
Coal*	47.4	50.8	47.4
Oil	10.6	6.8	10.2
Gas	8.8	21.1	24.8
Hydropower	33.2	21.3	16.7
Nuclear power	0	Negligible	0.9
	100.0	100.0	100.0

* Includes a relatively small amount of anthracite, amounting in 1969 to 0.4 percent of total.

† Preliminary figures.

Source: Calculated from data in references 3 (table 2) and 4 (p. 87).

coal still provides the major part of the energy consumed by electric utilities, there has been a slight decline in its relative contribution since 1959 (table 3).

Despite an absolute increase in output during the period, hydroelectric plants also provided a steadily decreasing percentage of total output. While hydroelectric output almost tripled, its growth was only half that of the total electric power generated, which increased six-fold.

Nuclear power plants, which produced only a negligible amount in 1959, produced almost 1 percent of the total electric power generated in 1969.

Table 4 shows the growth in fuel consumption from 1959 through 1969. During that entire period the coal and gas used were supplied primarily from domestic sources. For oil, however, the United States became increasingly dependent on foreign supplies. Net imports of crude and refined oil rose from 572.5 million barrels in 1959 (6, p. 390) to 1,069.2 million barrels in 1969 (7, p. 2).

TABLE 4—FUEL CONSUMPTION IN THE UNITED STATES, 1959-1969

Fuel	For electric power generation		Gain	For all uses		Gain
	1959	1969*	1959-1969	1959	1969*	1959-1969
Coal† (thousand tons)	168,423	310,600	142,177	385,056	517,289	132,233
Oil (million bbl)	88	255	167	3,455	5,037	1,582
Gas (billion cu ft)	1,629	3,790	2,162	11,585	20,350	8,765

* Preliminary figures. Source: 5, p. 1; 3, tables 3, 4, and 5; 1, p. 32; 2, p. 5.

† Principally bituminous coal and lignite but includes small amount of anthracite. Total tonnage in 1969 included 507,715,000 tons of bituminous and lignite and 9,574,000 tons of anthracite.

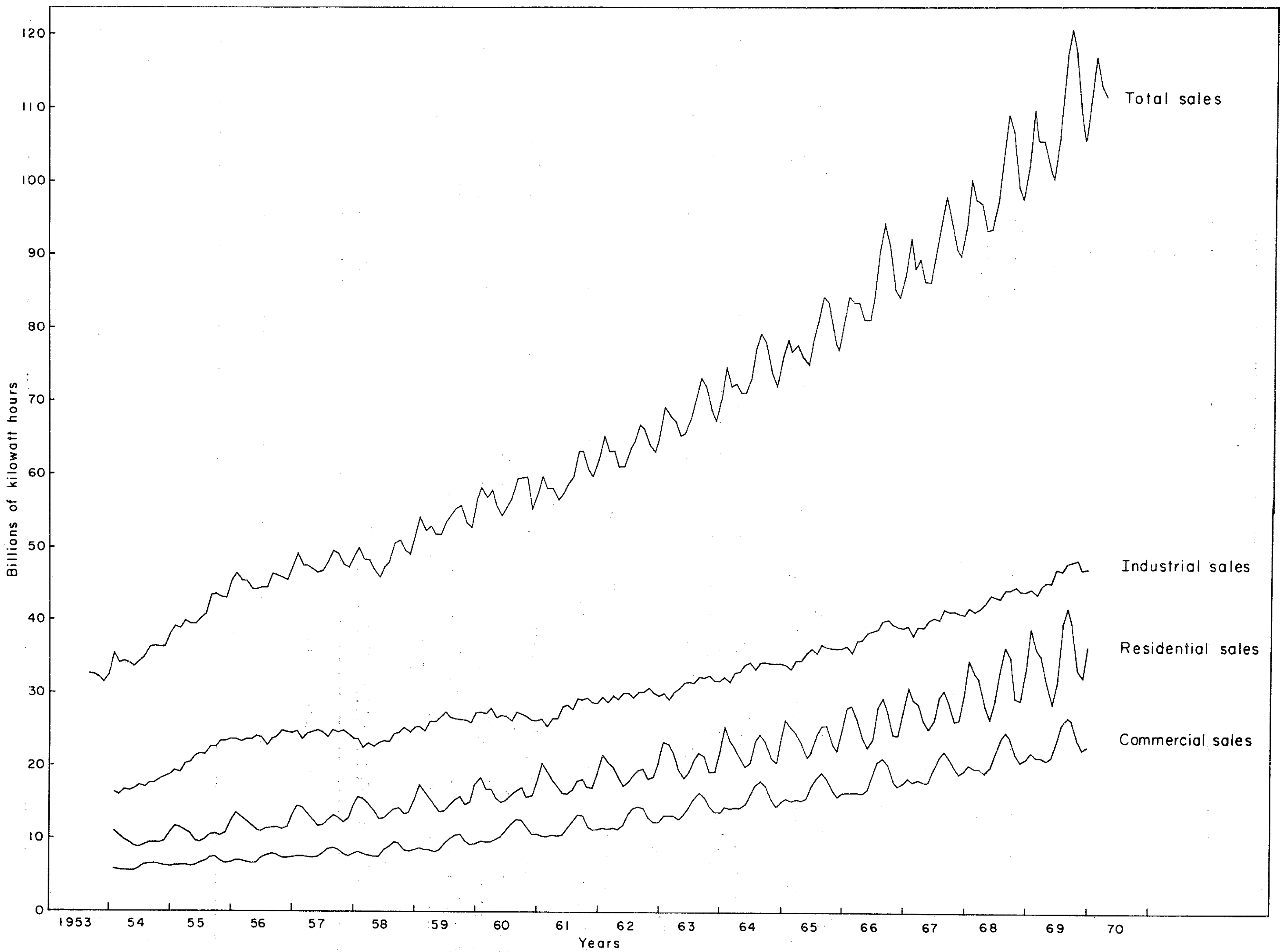


Fig. 1 - Monthly sales of electric energy by electric utilities in the United States, 1953-1969, by consumer category.

GROWTH PATTERNS IN ELECTRIC ENERGY

While rapid growth in use of electric energy has occurred in all parts of the nation, the pattern has differed somewhat in the various regions. Table 5, showing the growth in power provided by major utility systems, illustrates this variation. The national growth from 1958 to 1968 was 104.6 percent. Regional growths ranged from 81.6 to 165.8 percent.

TABLE 5—ELECTRIC POWER GENERATION BY REGION

Region	Million kilowatt hours			Percent increase	
	1958	1968	1969	1958-1968	1968-1969
Northeast (I)	125,755	251,341	271,348	99.9	8.0
East Central (II)	122,008	228,635	244,822	87.4	7.1
Southeast (III)	128,925	258,651	281,072	100.6	8.7
North Central (IV)	73,491	133,465	144,322	81.6	8.1
South Central (V)	62,376	165,799	186,590	165.8	12.5
West Central (VI)	12,284	27,507	30,484	123.9	10.8
Northwest (VII)	52,060	102,979	112,149	97.8	8.9
Southwest (VIII)	60,868	136,716	146,596	124.6	7.2
Contiguous U. S. Total	637,767	1,305,093	1,417,383	104.6	8.6

Source: 8, p. 5; 9, p. 13.

A significant change in recent years has been the shift of the period of "peak," or heaviest, consumption from winter to summer, resulting primarily from the growing use of air conditioning by residential and commercial consumers. Figure 1 shows the monthly sales of electric energy by utilities in the United States by major categories of use and total use. In the earliest years shown on figure 1 the peak of total sales occurred in winter. Not until 1959 did the summer peak significantly exceed the peak of the preceding winter. In 1964, however, the summer peak exceeded not only the peak of the preceding winter but also that of the winter that followed.

The first evidence of increased summer sales appears in sales to commercial customers (fig. 1), as air conditioning found application in theaters, stores, and other commercial installations. Summer residential sales began to show an increase in the mid-1950s, but not until 1966 was the summer peak equal to the preceding winter peak. Industrial use of electric power shows some variation from month to month but no especially prominent seasonal peak. The wide seasonal variations in demand, therefore, can be attributed almost entirely to residential and commercial use of electricity.

The sales of kilowatt hours shown in figure 1 are a measure of the quantity of energy used during each monthly period but give no indication of the highest level of demand that occurred during the month. It is for the peak level of demand, however short the duration, that utilities must provide in planning their capacity. To assure a dependable supply of power, additional capacity must also be available to cover generating equipment idled for repairs, maintenance, or for other reasons.

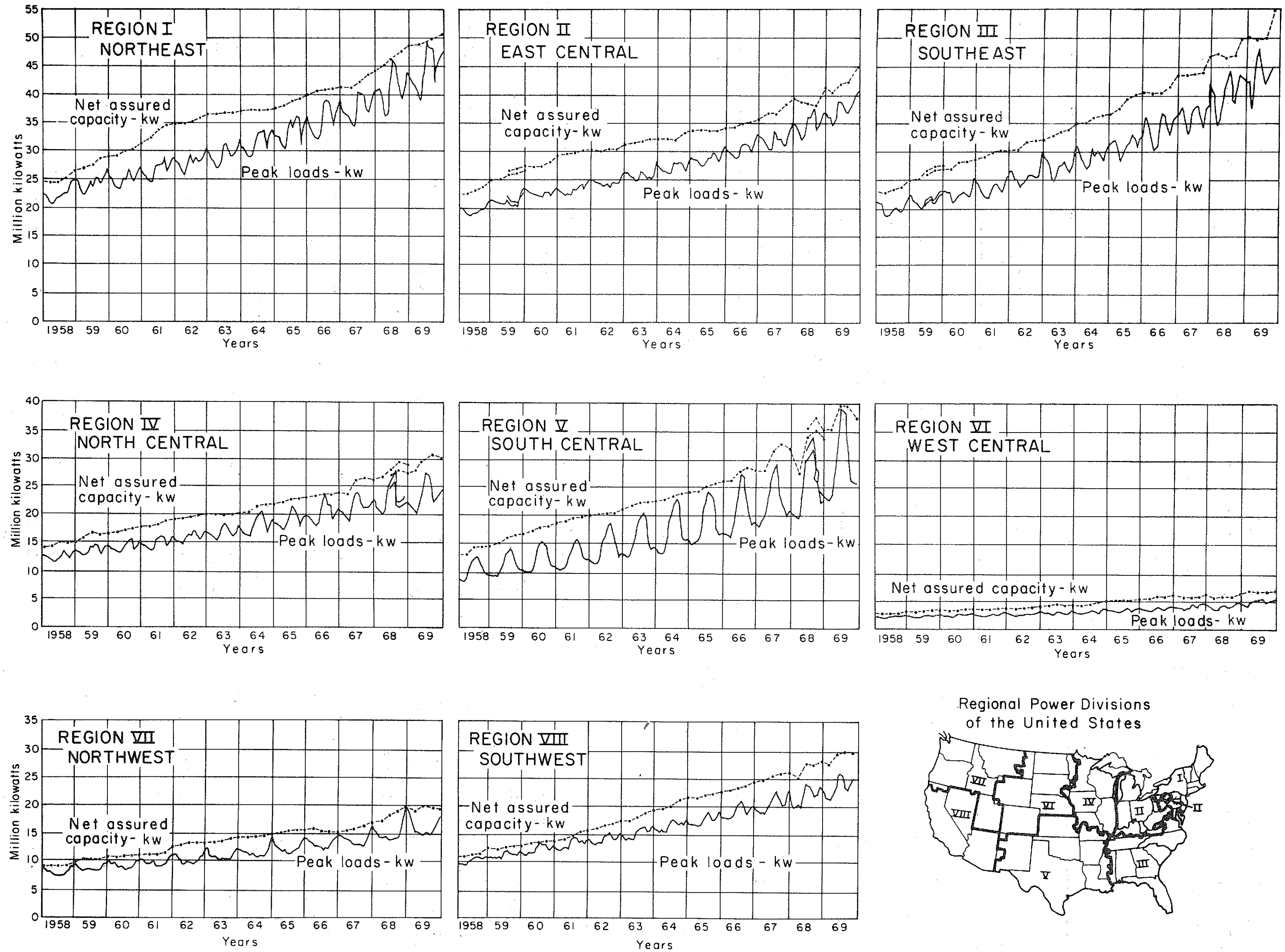


Fig. 2 - Net assured generating capacity versus monthly peak loads in regional power divisions of the United States, 1958-1969. Borders of Regions II and III were changed in 1959; borders of Regions IV and V were rearranged in 1968.

The availability of capacity to meet peak demand means that some of the generating equipment often is utilized at less than full capacity. Until the last few years, generating capacity was designed to meet the high winter demand. As a result most plants operated at a low level during the summer months. The widespread growth in the use of summer air conditioning produced increased summer demands for power, and, for a time, a better balance and better use of capacity. But the rapid growth in summer peaks soon brought the problem of providing adequate capacity during that season.

Figure 2 shows the trends in peak demand and net assured generating capacity available for the eight regions of the United States. (Net assured generating capacity is that available to meet normal power requirements and is based on dependable installed capacity, including hydroelectric capacity under adverse [low] water conditions, minus required capacity reserves.) The shift to summer peaks from winter peaks, as shown by statistics of the Federal Power Commission, varied in the eight regions (table 6).

TABLE 6--YEAR IN WHICH SUMMER LOAD FIRST EXCEEDED PRECEDING WINTER PEAK

Region	Year
South Central	pre-1948
Southwest	pre-1948
Southeast	1950
North Central	1953
East Central	1955
West Central	1958
Northeast	1959
Northwest	winter peak remains

While consumption of electricity grew rapidly for all uses, the rate of growth in recent years has been most rapid in the residential market, as is shown in figure 1 and table 7. Of the 357 billion kilowatt-hour increase in consumption from 1965 to 1969, about 38 percent was for residential purposes. Part of the growth in residential use is related to increased population, but per capita use also has risen significantly. From 1965 to 1969 annual per capita consumption for residential uses grew from 1,498 kilowatt hours to 2,114 kilowatt hours, a gain of 41.1 percent. Total per capita consumption of electric power for all purposes increased 32.3 percent.

A number of factors contributed to a more rapid growth in residential use than in other uses. Among them was the proliferation of electrical devices and appliances, ranging from major household appliances, such as ranges and home freezers, to electric shavers and toothbrushes. Another was the increasing size of some of the appliances used. Although a few years ago a 12-cubic-foot refrigerator might have been considered large, combination refrigerator-freezers of more than 20-cubic-foot capacity are not now uncommon. The major cause for the increase in electric power consumption in recent years, however, has been the increased use of air conditioning, television, and, to some extent, electric space

TABLE 7—SALES OF ELECTRIC ENERGY TO ULTIMATE CONSUMERS IN 48 CONTIGUOUS STATES, 1965 AND 1969

Consumer	Thousand kilowatt hours 1965	1969	Absolute gain 1965-1969	% Gain 1965-1969
Residential	289,859,793	424,624,734	134,764,941	46.5
Commercial	199,780,913	279,542,853	79,761,940	39.9
Industrial	427,572,314	558,054,272	130,481,958	30.5
Other	33,506,233	45,789,289	12,283,056	36.7
Totals	950,719,253	1,308,011,148	357,291,895	37.6

Source: 9, p. 26; 10, p. 26.

heating, particularly in certain areas of the nation. The increased use of electricity to operate conventional types of heating equipment also is a factor.

Growth in the use of major electrical appliances is indicated by table 8. Especially significant from the standpoint of residential power consumption in the four years from 1965 to 1969 are the gains of about 31 percent in the number of homes with electric ranges, 47 percent in those with television sets, and 129 percent in the number of homes with room air conditioners. The table gives no indication of the number of homes in which more than one electrical unit of the same type is in use.

TABLE 8—NUMBER OF HOMES WITH SPECIFIC MAJOR ELECTRIC APPLIANCES

Appliances	Millions of homes 1953	1960	1963	1965	1967	1969	Percentage of homes 1969
Air conditioners, room	0.6	6.5	7.2	11.4	17.6	26.1	42.5
Freezers	0.9	11.2	11.2	15.1	15.1	17.5	28.1
Radios	43.7	50.0	NA	55.2	58.6	61.1	99.7
Ranges	10.2	18.0	19.0	23.4	26.3	30.6	49.9
Refrigerators	37.8	49.6	53.1	56.0	58.6	61.1	99.7
Television							
black and white	19.8	45.5	50.0	53.1	57.6	60.3	98.5
color		NA	0.1	2.9	8.8	21.9	35.7
Washers, clothes	32.2	42.0	39.9	49.0	51.9	58.1	94.8
Water heaters	5.8	9.4	NA	13.1	14.5	17.0	27.8

NA = Figures not available.
Source: 11, p. 754; 12, p. 710; 13, p. 704.

All of the appliances contribute to the total consumption of electric power, and most do so on a year-round basis. Major exceptions are those used for heating in winter and cooling in summer. Although it is largely the increase in air conditioning that has caused the growth in summer use of power and a shift in peak demand from winter to summer, equipment such as coolers, refrigerators, and freezers also use more power in summer by operating a greater percentage of the time.

PROBLEMS OF INCREASING CAPACITY TO MEET GROWING DEMANDS

From December 1957 to December 1969, the installed generating capacity of electric utilities in the contiguous United States grew from 128.74 million kilowatts to 306.08 million kilowatts (14, p. 1; 9, p. 11). Despite this 138 percent increase in 12 years, the net assured capacity in many regions grew at a slower pace than demand and provided little or no margin of safety. The margins between the assured capacities and peak demands of individual or interconnected systems vary in the same manner as they do among regions. Late in 1969 it was reported that 39 of the 181 major systems in the United States had a reserve capacity of less than 10 percent (15, p. 48).

In many areas of the nation today the individual electric utilities are interconnected by systems that provide for mutual assistance for times of overload or partial breakdown. The ability to pass power back and forth provides each utility with a margin of protection that would be impractical if each had to provide fully for itself.

Under normal weather patterns there is likely to be a wide variation in temperature within areas of even moderate size at any one time. With the movement of successive warm and cold fronts across an area, the shift of power among the cooperating utilities can be made first in one direction and then the other.

In hot, humid weather a utility may find as much as a third or more of its peak demand resulting from air conditioning. Figure 3, based on data supplied by a single utility, indicates the relation between peak power demand and temperature range in July of 1968, 1969, and 1970. The temperature was recorded at a point near the center of the area served by the utility. For each year, the individual week day of July on which the highest and lowest kilowatt peak demands occurred were selected. A horizontal line was drawn (fig. 3) at the level of the peak demand for each day. The length and position of the line also indicate the temperature range, and the heavy square or dot shows mean temperature. In figure 3, the mean temperatures for the days of highest and lowest peak power demands for the three respective years are connected by dashed lines. High peaks were about 50 percent above low peaks, but in July of 1970, when the difference in mean temperatures for the high and low peak days was 20.5 degrees and the high temperature reached 100° F, the higher peak demand for power was 54.8 percent above the lower one. That the peak demands also have increased with each successive year is evident, indicating a greater use of air conditioning throughout the utility area each year.

The rapid surge in demand for electric power has outpaced the net assured capacity available to meet that demand (fig. 2). From 1960 to 1965 the level of peak demand for power in the contiguous United States increased 39 percent, whereas generating capacity increased only 26.6 percent. In the succeeding four years, 1965 to 1969, peak loads increased by 40 percent and capacity by 34.2 percent. For the total 9-year period, 1960 to 1969, the increases were 94.7 percent in peak demand and 70 percent in generating capacity. Part of the deficit has been met by better utilization of generating capacity through an exchange of power between utilities. This, however, has not fully compensated for the lag.

Two especially important factors in the lag between demand and capacity growth have been (1) the difficulty of predicting load growth sufficiently far in advance to plan adequate new facilities, and (2) the increase in lead-time required to move a project from the initial planning stage to completion and full operation.

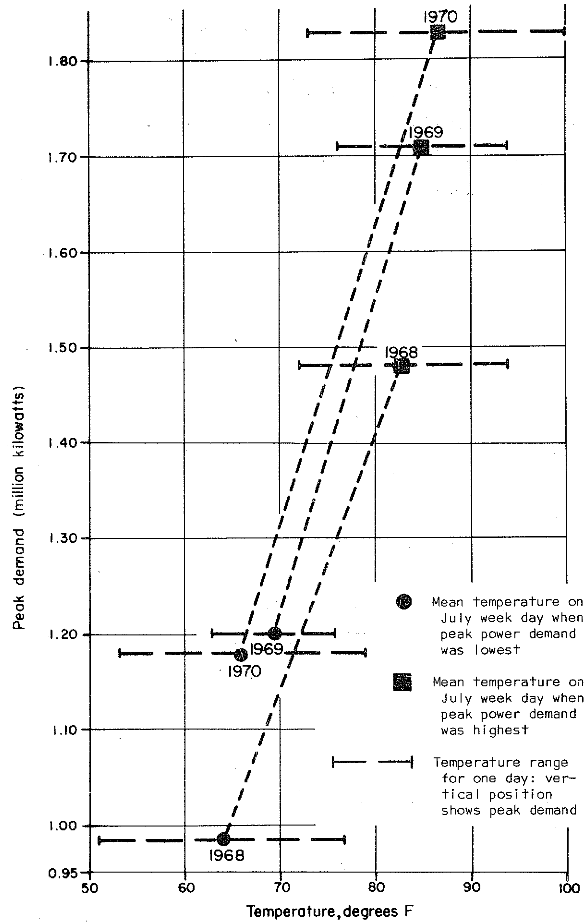


Fig. 3 - Temperature range and mean temperature, versus electrical load for an individual electric utility system on days of highest and lowest demand in July 1968, 1969, and 1970.

The steady increase in the winter peaks of power demand in the years prior to 1960 had established a pattern that enabled planners to predict their future needs sufficiently far in advance to be able to construct additional facilities in time to meet demand. Figure 4 shows that a fairly constant margin has been maintained between net assured generating capacity and winter peak demands for the United States as a whole. This was true, too, for the individual regions, most of which also were able to maintain a margin above their winter peaks (fig. 2). As shown in figures 2 and 4, the summer peaks now constitute the problem.

Once the summer peaks exceeded those of winter, they became the critical factor in the need for capacity. Their growth, which was dependent both on summer temperature variations and on the rate at which the use of air conditioning increased throughout the various regions of the country, was less predictable.

A comprehensive National Power Survey was undertaken by the Federal Power Commission in 1964 to assess the future power requirements of the nation

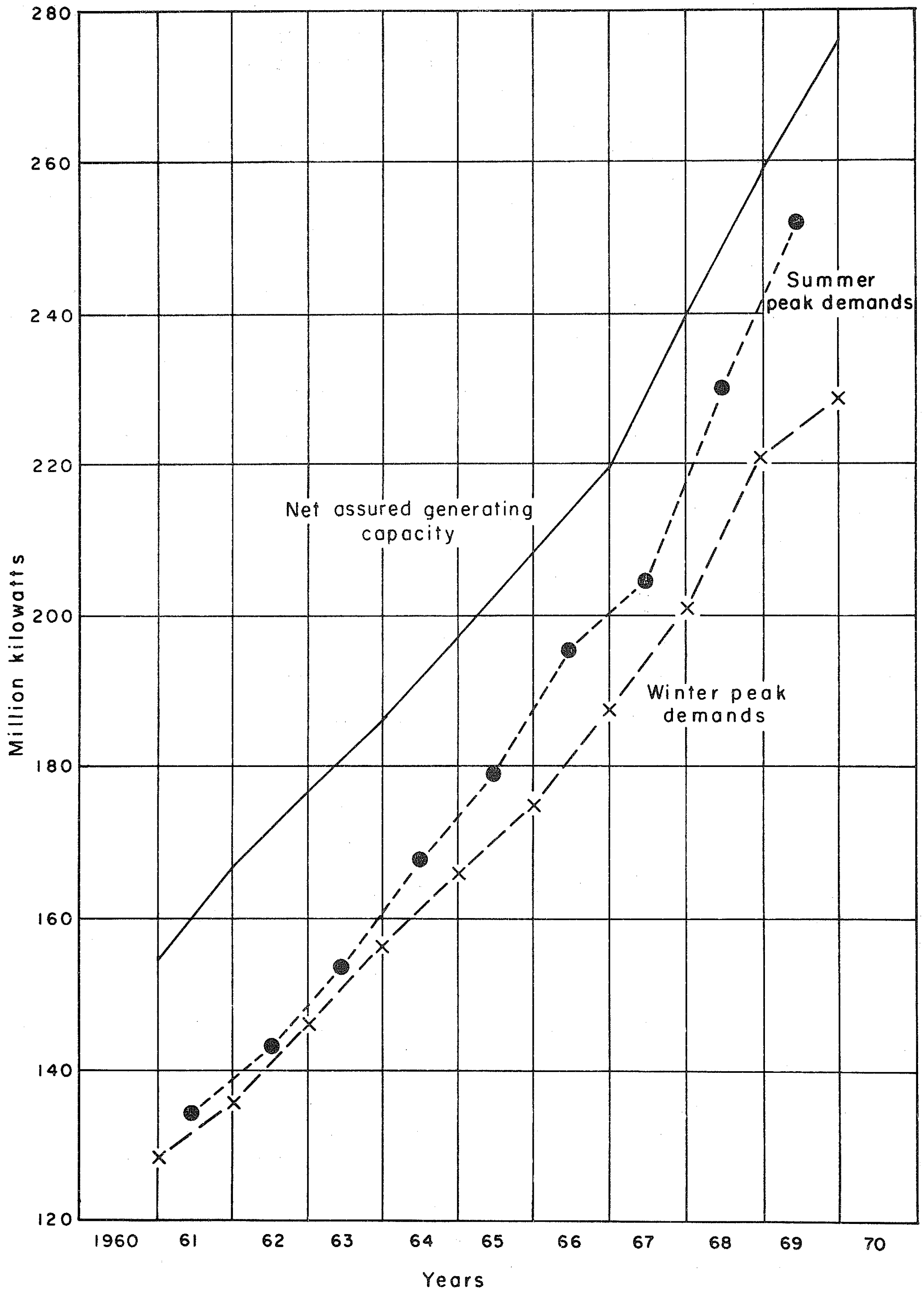


Fig. 4 - Trends in net assured generating capacity and summer and winter peak loads of electric utilities in the United States.

and outline means by which those needs could be met. Projections were made of peak demands for each region for the years 1970 and 1980 (16, p. 39). These projections, together with actual peak demands for 1968 and 1969, are shown in table 9. The rapidity with which air-conditioning equipment has come into general use, with the consequent high summer peaks in energy demand, could not be accurately predicted at the time of the survey. Nevertheless, it does not appear that for the United States as a whole the actual 1970 peaks will be much, if any, higher than the peaks projected six years earlier. For some of the regions, however, peaks will definitely be higher.

TABLE 9—PROJECTED AND ACTUAL ELECTRIC UTILITY REQUIREMENTS

Region	Projected peak demand*		Actual peak demand		1969 demand as % of 1970 projections*
	1970	1980	1968	1969	
Northeast (I)	49.4	86.6	45.6	49.0	99.1
East Central (II)	44.7	78.1	37.7	39.7	88.1
Southeast (III)	52.3	97.9	44.6	48.3	92.3
North Central (IV)	31.0	56.9	28.2	27.4 †	97.8
South Central (V)	36.6	69.0	31.7	38.7	
West Central (VI)	6.8	12.4	5.1	5.7	83.8
Northwest (VII)	21.1	39.6	19.0	17.8‡	71.6
Southwest (VIII)	28.2	52.7	24.4	26.3	93.3
Totals	270.1	493.2	236.3	252.9	93.6

* Projections made in 1964.
† Changes in the borders of these regions made in 1968.
‡ December peak. All other peaks shown are summer peaks.
Source: 16, p. 39.

Projections of future peak requirements, ranging up to three or more years in advance, are made annually by the individual utilities and then combined and published by the Federal Power Commission. The advance estimate for each year is adjusted as that year approaches. Figure 5 shows advance estimates and actual peaks. Estimates for summer peaks have been available only since 1967. The difficulty in anticipating peak growth with accuracy very far in advance and the need for adjustment are evident.

Once the projections are made, there remains the problem of constructing new capacity in time to meet the anticipated needs. In recent years it has been increasingly difficult to maintain the scheduled level of construction.

Proposed nuclear plants have met with most of the delays in authorization or approval, but hydroelectric and fossil fuel plants also have been delayed or refused in some areas. Delays of this type resulted from public opposition to power plant construction of any kind. Generating facilities that actually have been planned and on which construction has begun have been delayed at every stage, including the actual plant construction and the manufacture, delivery, and assembly of equipment.

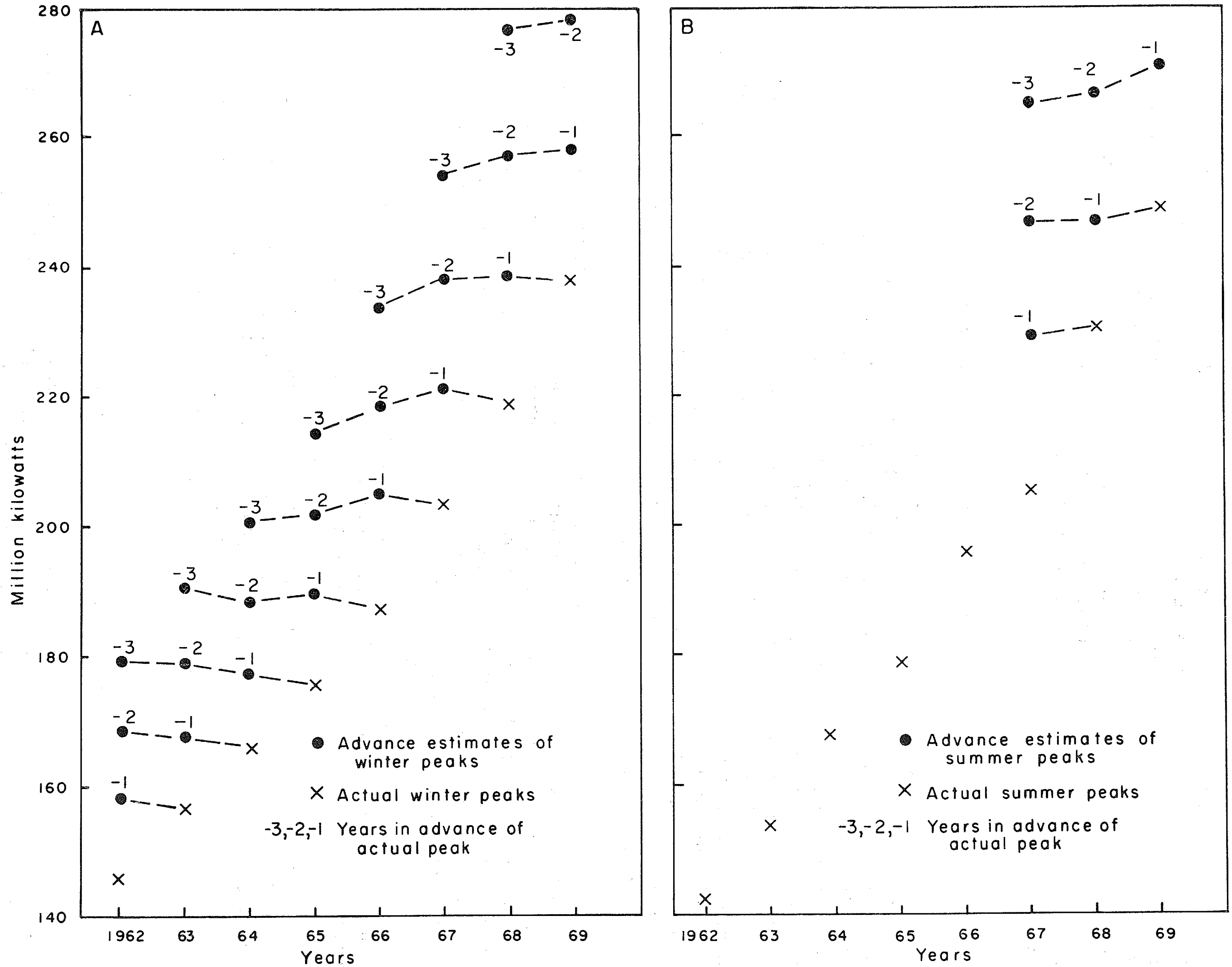


Fig. 5 - Advance projections and actual peak loads of electric power demand of utility systems in the United States, 1962-1969. A - Projected and actual winter peaks; B - Projected and actual summer peaks.

ENVIRONMENTAL ASPECTS OF POWER GENERATION

The generation of electric power by any of the means now commercially available carries with it some effects on the environment and the problems related thereto. Among the problems that must be dealt with are those created by the modification or alteration of the environment resulting from the construction of dams for hydroelectric plants, the emission of combustion products by steam plants fired by fossil fuels, radioactive emission and the disposal of radioactive waste from nuclear steam plants, and the disposal of waste heat from all types of steam plants.

Effects of Hydroelectric Power Generation

In 1969 hydroelectric plants operated by electric utilities in the United States produced 250,078 million kilowatt hours of electric power (3, table 1), 17.6 percent of the total electric output. (Note: This differs slightly from the estimated 16.7 percent of energy input in table 3.) While hydroelectric plants, unlike units powered by fossil fuel and nuclear reaction, do not contribute to air or thermal pollution, the expansion of hydroelectric capacity is likely to be relatively limited in the future. This is true despite the fact that in 1967 the estimated undeveloped water power potential was almost three times that actually developed (13, p. 518). However, about 25 percent of the undeveloped potential lies in Alaska, 18 percent in the state of Washington, and about 34 percent in other Rocky Mountain and Pacific states. The potential east of the Mississippi River where power demand is greatest constitutes only 17.3 percent of the undeveloped potential.

Future development of hydroelectric power will be retarded because the most suitable and economically practical sites have already been developed. There is also growing public opposition to the further damming of streams and rivers because of possible adverse environmental and ecological effects. The dams necessary for hydroelectric installations form lakes that inundate large areas of land, retard the flow of water in rivers, and block the movement of fish upstream unless fish ladders are constructed.

The inability of water power to cope with the growing demand for power is illustrated in the area of the Tennessee Valley Authority, where the most extensive hydroelectric system of the nation is located. Power demand in the area has grown so great that it has been necessary to supplement the 3.1 million kilowatt capacity of its hydroelectric plants with coal-fired and nuclear installations. The steam generating capacity of the TVA is now 5 times its hydroelectric capacity (17, p. 22). In fiscal 1969, TVA used 30.9 million tons of coal (17, p. 41), which constituted 10.3 percent of the coal burned by all electric utilities in the United States between July 1, 1968, and June 30, 1969 (18, p. 8; 19, p. 6).

Effects of Combustion of Fossil Fuels

Of the three fossil fuels, coal, oil, and gas, natural gas is the cleanest burning. The combustion products it produces are well within the limits of present emission regulations. Oil and coal contain sulfur compounds in varying degrees, which, on combustion, are converted to oxides of sulfur. Increasingly stringent limits are being placed on the quantities of sulfur dioxide that can be exhausted into the air by fuel-burning units. To control sulfur oxide emission, the limitations usually are placed on the amount of sulfur contained in the fuel itself.

Processes are available for desulfurization of fuel oil. The cost of such processing is reported to be 40 to 55 cents per barrel, or about 3½ to 6 cents per million Btu (20, p. 49).

No process has yet been developed that will completely remove the sulfur from coal prior to combustion, although much research has been done on the subject. One research effort involves modification of the coal into a new fuel product by solvent refining, and it is reported to have commercial promise (21). Research on the chemical removal of sulfur oxides from the combustion gases has been going on for several years, and various processes have been tested in a few commercial operations on a relatively limited scale. The economic feasibility of using any of these processes on a large scale remains to be proved, but success is anticipated within the next few years (22, p. 4).

In the combustion of coal, a second objectionable by-product is particulate matter in the form of fly ash. The emission of fly ash can be controlled by devices that electrically precipitate, or otherwise remove, the material from the stack gases. Experience has shown, however, that these precipitators are less effective with ash from coal that contains no sulfur than with ash from coal in which sulfur is present. In some cases, utilities have found that limited addition of sulfur trioxide to the stack gases improved the effectiveness of their ash-collecting electrostatic precipitators (23, p. 22). A further environmental problem is the disposal of the collected ash. However, the ash has proved to be of value in various economic processes. It is used, for example, in the manufacture of brick and as an additive in concrete (24).

Effects of Nuclear Power Generation

Although nuclear power plants do not produce fly ash or sulfur oxides, they do present other types of environmental problems. Public concern regarding nuclear generating plants stems primarily from fear of radioactive emission from the plants and the possibility of catastrophic accidents to the plants, which might have widespread effects. Despite repeated assurances by the Atomic Energy Commission that no appreciable hazard exists, these fears persist, and public opposition to nuclear plants has not subsided.

A second environmental problem connected with nuclear plants is the safe and permanent disposal of radioactive waste materials that are produced as a result of electric power generation. These materials are of various "levels" of radioactivity, and their treatment and permanency differ for the various levels. A recent report of the Atomic Energy Commission describes these differences.

> Radioactive wastes are generated in practically all areas of the nuclear fuel cycle and accumulate as either liquids, solids, or gases at varying radiation levels. The liquid radioactive wastes are generally classified as high, intermediate, or low level, based on the concentration of radioactivity.... High level liquid wastes are those which, by virtue of their radio-nuclide concentration,

> half-life, and biological significance, require perpetual isolation from the biosphere.... (25, p. 251.)
>
> Intermediate level liquid wastes is a term applicable only to radioactive liquids in a processing status which must eventually be treated to produce a low level liquid waste (which can be released) and a high level waste concentrate (which must be isolated from the biosphere). Low level liquid wastes are defined as those wastes which, after suitable treatment, can be discharged to the biosphere without exposing people to concentrations in excess of those permitted by AEC regulations.... (25, p. 252.)
>
> The term "low level", as frequently applied to commercial burial sites, refers to the hazard potential of the radioactive material buried and should be interpreted as indicating little likelihood of dispersal into the environment, either by water or by air, of the radioactive material.... (25, p. 253.)

The development of a suitable permanent means of disposal of high level waste is especially crucial if nuclear energy is to play the important future role predicted for it. The more than 80 million gallons of high level waste solutions generated prior to 1969 are still in storage in special underground tanks at AEC installations in Idaho, Washington, and Georgia.

AEC estimates indicate that cumulative high level wastes from civilian nuclear power plants will reach 4.4 million gallons by 1980 and 60 million gallons by 2000. If these liquid wastes are solidified, the cumulative volumes for 1980 and 2000, respectively, will be 44,000 cubic feet and 600,000 cubic feet (25, p. 262, 264).

Several procedures for disposal of solid high level waste have been considered. Among them is disposal by permanent burial in thick underground beds of salt, a method that appears to have considerable promise (26). Until a means of suitable permanent disposal is developed and becomes operational, these wastes, which retain radioactivity for hundreds of years, will constitute a most serious problem.

In addition to problems involved in the disposal of solid and liquid wastes is that of the release of radioactive gases to the atmosphere from fuel reprocessing plants. The gas creating most concern is krypton, which has a half-life of 10.76 years, and it may prove to be a limiting factor in the design and location of future atomic fuel plants (27, p. 395).

A further potential problem in the future expansion of nuclear energy may be the availability of fuels, and this is discussed in the section of this report dealing with fuel supplies.

Thermal Pollution

The generation of a kilowatt hour of electricity in steam plants that burn fossil fuels requires, on the average, about 10,500 Btu of fuel heat energy. About 40 percent of this energy is converted to electrical energy, 10 percent is exhausted into the stack, and 50 percent is transferred to the cooling water and discharged from the plant (28, fig. 4). In 1969 the input of coal, oil, and

TABLE 10--TRENDS IN FUEL CONSUMPTION, PER KILOWATT HOUR PRODUCED, IN STEAM-ELECTRIC GENERATION PLANTS, 1949-1967

Year	Coal*	Oil†	Gas‡
1949	1.240	0.099	14.9
1958	0.904	0.081	11.4
1967	0.869	0.076	10.3
	Percentage of change in fuel consumption per kwh		
1949-1958	-27.1	-18.2	-23.5
1958-1967	- 3.9	- 6.2	- 9.6

* Pounds per net kwh
† Gallons per net kwh
‡ Cubic feet per net kwh
Source: 29, p. 35, 36, 37; 30, p. 99, 100, 101

gas energy into power generation was estimated at 12,972 trillion Btu (3, table 2). If half of this heat was discharged as waste heat in cooling water, 6,486 trillion Btu was lost. This would be sufficient heat to raise by 140° F the temperature of a body of water with a volume of 5 cubic miles. One author has estimated that if present power trends and technology should continue, by the year 2000 power demand in the United States will be so great as to require, as coolant, an amount of water equivalent to about 50 percent of all the water flowing across the surface of the nation (31, p. 98).

Although the total amount of heat discharged has been increasing, the heat energy required per unit of power generated has decreased. Efficiency in the use of fuel energy by electric generating plants has been greatly improved in recent years, as shown in table 10. The average coal consumption per kilowatt hour produced dropped from 1.24 pounds in 1949 to 0.87 pounds in 1967. In 1920 it was 3.00 pounds. Similar improvements have occurred with other fuels. It appears unlikely, however, that significant further improvements can be anticipated, as indicated by the declining rate of improvement during recent years (table 10).

Another factor that will tend to retard, or perhaps reverse, the decline in heat discharge per unit of power generated is the trend toward nuclear plants. Present nuclear plants discharge about 40 percent more heat than fossil fuel plants (28, fig. 4), or about the level discharged by fossil fuel plants 20 years ago.

Concern over the environmental effects of the discharge of heat into natural bodies of water is steadily mounting. Increases above the natural temperature of lakes and streams is reported to effect changes in the growth rate and, in some cases, the species of aquatic flora and fauna (31). Some evidence indicates that at some locations certain forms of aquatic life are benefited by increased water temperatures and that warm water used in irrigation could help promote plant growth. In general, however, the ecological effects of increased temperature have been considered detrimental, and opposition to increasing water temperatures is growing.

The problem of thermal pollution can be mitigated somewhat, at an increased cost, by the use of cooling towers to reduce the water temperature before discharge. This will involve greater actual consumption of water because some will be lost through evaporation during cooling. However, unless some economical means of utilizing the vast quantities of waste heat can be developed, the power industry will be faced with increasingly stringent regulation of discharge temperatures.

FACTORS IN THE PRESENT POWER CRISIS

The power crisis confronting various parts of the nation in 1970 will extend into 1971 and perhaps beyond 1972. With peak demands steadily approaching the net assured capacity (fig. 4), little margin of safety exists for the summer months, and dwindling supplies of fuel raise questions as to whether the peaks of the coming winter months can be met. On numerous occasions in the past 3 years it has been necessary for major utility systems to reduce their voltage and to ask customers to reduce their consumption of power in order to get through emergency periods.

Generating Capacity

To solve the problem of inadequate generating capacity, it will be necessary not only to overcome the delays that are making present construction run behind schedule but also to build additional capacity at a faster rate in the future. The necessity to cancel, postpone, or modify planned additions because of public opposition to new plants has affected the level of generating capacity in many parts of the country. The five examples following illustrate the nature and causes of part of the delays and the fact that such opposition is widespread.

1) On December 10, 1962, Consolidated Edison Company of New York filed a proposal with AEC for a nuclear power plant intended for operation in 1970. In 1964 it cancelled its proposal because of public concern and opposition (32).

2) Pacific Gas and Electric Company withdrew its application to AEC to build a nuclear plant at Bodega Head, California. The site, only 1,000 feet from the edge of the San Andreas Fault, which produced the San Francisco earthquake of 1906, was considered unsuitable (33).

3) Construction of a nuclear plant by New York State Electric and Gas Company on Cayuga Lake at Ithaca, New York, was halted because of potential thermal effects on the lake (34).

4) A new nuclear plant under construction by the Northern States Power Company at Monticello, Minnesota, is virtually completed and ready for operation under safety standards established by the AEC. However, the state of Minnesota has established radioactive emission standards 50 times more stringent than those of the AEC, which, if upheld, will delay the operation of the plant indefinitely. The power company is suing the state of Minnesota in an effort to have the state standards overruled by establishing the higher authority of the AEC (35, p. 56).

5) The 1963 application of Consolidated Edison of New York to build a pumped-storage hydroelectric plant at Storm King Mountain, near West Point, New York, was not approved until 1970. The plant, originally scheduled for operation in 1967, will begin operation in 1977. The 7 year delay in obtaining approval resulted from opposition by conservation groups seeking to preserve the site as a wilderness area (36, p. 26).

A proposal has been made recently that Federal legislation be passed requiring utilities to give public notice of plans involving individual power plant sites 5 years in advance and 15 years notice of plans for regional power developments (37, p. 19). States would be required to create agencies to settle disputes arising between those proposing and those opposing new sites. Utilities would be allowed increased rates to cover the extra costs involved in the acquisition of alternate sites. Such legislation, if put into effect, would give opponents an opportunity to voice their objections in advance and should, at the same time, enable the utilities to make their plans with confidence once a site had been approved.

Delays in delivery of ordered equipment have slowed completion of some plants. Manufacturers attribute at least part of this to the large influx of orders in the late 1960s that exceeded the factories' capacity. Other difficulties were encountered in the fabrication or assembly of equipment at the plant sites, especially equipment for nuclear plants.

Noting the delay in completion of nuclear plants, the AEC in a 1969 report attributed a major part of the problem to the new skills and experience required in construction of such plants:

> In early 1968, most utility executives expected that their nuclear plants for commercial operation in 1969 and 1970 would be on schedule. In contrast to the confidence expressed at that time, it now appears that only two of those 13 plants will be on the original schedule. The other 11 plants are experiencing delays of from about two to 13 months, due to many reasons, such as, late pressure vessel deliveries, regulatory requirements and proceedings, but predominantly due to the lack of experience in building nuclear plants and the inability to obtain experienced labor and craftsmen during the construction phase.... (24, p. 18.)

In the fall of 1970, plant construction was still behind schedule. A survey of 10 nuclear power plants was reported to have shown that average construction time had increased from the initially planned 4 years and 1 month to an actual 5 years and 2 months. Newly planned nuclear plants were expected to require 6 or 7 years for completion (38).

Delays also have occurred in construction of fossil fuel plants, although they generally still take 2 or 3 years less time to construct than nuclear plants.

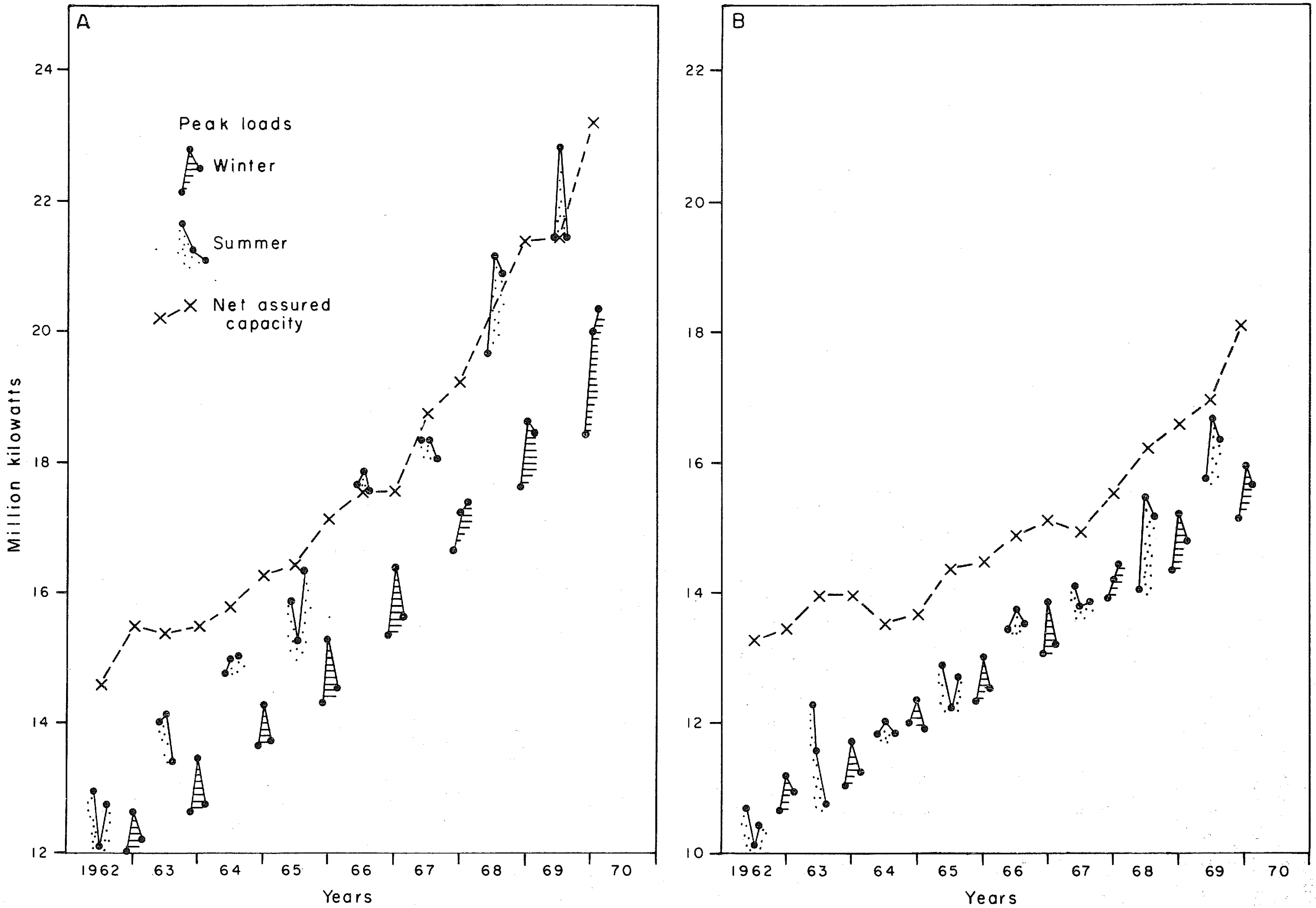


Fig. 6 - Net assured generating capacity versus summer and winter peak demands for major interconnected networks. A - Interconnected Pennsylvania, New Jersey, and Maryland systems; B - Interconnected New York Power Pool and New York State systems.

Breakdowns or construction delays may involve or affect only a small percentage of the nation's total generating capacity. However, loss of even a single unit by an individual utility may be sufficient to completely disrupt its capability for meeting local or regional demands.

In the Northeast Region, which has the highest peak demand of any section of the nation (fig. 2), the demand rose to full assured capacity in the summer of 1968 and has continued to do so every summer since. For some of the areas within the region the situation is even more critical. The capacity/demand relations of two of the major interconnections within the region are shown in figure 6. In 1969 the loss of a single 1 million kilowatt unit would have been a loss of only about 2 percent to the Northeast Region. To the Pennsylvania-New Jersey-Maryland interconnection it would have meant a 4.3 percent loss, and to the New York state interconnection it would have meant a 5.5 percent loss of capacity.

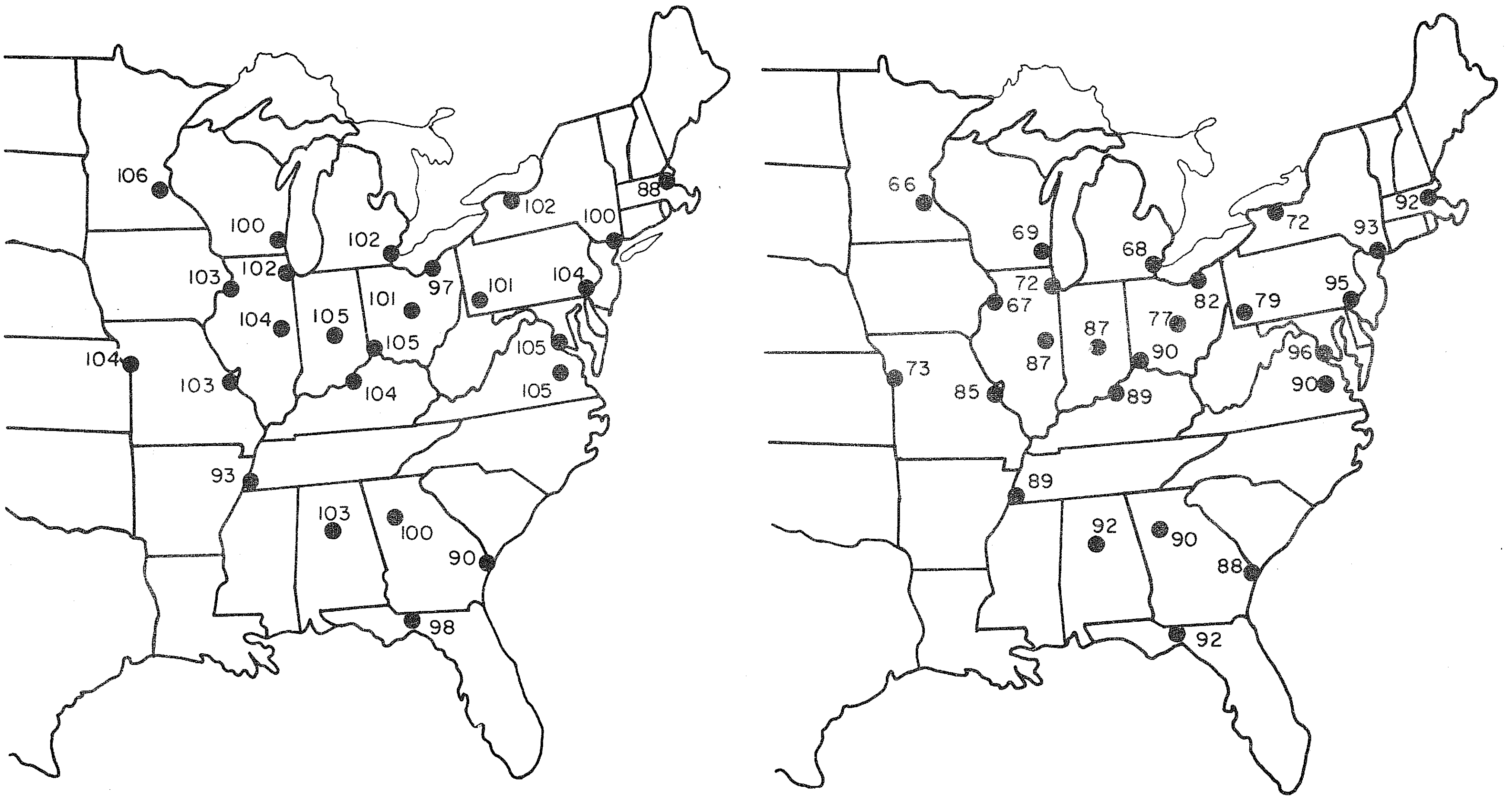
With the breakdown of two units in July 1970 (39), the Consolidated Edison Company suffered a 17 percent loss of capacity. Through a cutback on delivery to some customers, a reduction in voltage, and support from other utilities, the company was able to maintain service without total interruption. At the end of September 1970, a hot spell that covered the eastern seaboard led to power reductions throughout much of that area (40). Again the sharing and transfer of generating capacity helped to meet the load.

Because peak demands seldom occur simultaneously over wide areas, the interconnected utilities usually are able to exchange power to meet unusual needs. Under normal conditions, temperatures are sufficiently diverse that summer air-conditioning loads reach their peaks in different areas at different times. Despite the problems encountered in the summer of 1970, the weather was not as adverse as it might have been. The nation in general has been fortunate in that since the advent of widespread air conditioning there has not been a repetition of the weather that occurred in the summer of 1936. Despite the power shortages that plagued the East Coast on September 23, 1970, and the days immediately following, the maximum temperatures were much lower than those occurring on July 10, 1936 (fig. 7). A repetition of the 1936 temperatures at any time before a better capacity/demand situation is developed could be disastrous.

PROBLEMS OF FUEL SUPPLY

In 1968 and 1969, utilities of the nation began to face problems of fuel supply. Since that time the situation has steadily worsened and fuel, rather than generating capacity, may be the critical factor during the winter of 1970-1971 and for some time thereafter. Gas, oil, and coal are all in short supply, and, while the general growth in demand for energy has been somewhat responsible for the shortages, other special factors involving the individual fuels also have contributed to the low stocks of fuel.

Utilities historically have selected the fuel that would enable them to generate power at the lowest unit cost. In general, this meant using the fuels indigenous to the area in which the power plant stood. In Texas, Louisiana, and Oklahoma, natural gas is the only fuel used by utilities. In Kentucky, West Virginia, and Pennsylvania (except for the Philadelphia area), coal is used



July 10, 1936

September 23, 1970

Fig. 7 - Peak temperatures in major cities of the eastern United States on July 10, 1936, when 20 of 25 cities had temperatures reaching or exceeding 100 degrees, and on September 23, 1970, when east coast areas were confronted with major power shortages.

exclusively. Coal is also the exclusive fuel in Vermont and Michigan, although the coal must be shipped in from outside sources. In most other states utility fuel consists of a combination of coal, gas, and oil, although significant quantities of oil are burned only in the coastal states, where it arrives via water.

Figure 8A shows the trends in the use of fuels for electric power generation. From 1958 through 1968 the use of coal by utilities grew 92 percent, that of natural gas 151 percent, and that of oil 166 percent. From 1968 to 1969 consumption of coal, gas, and oil increased 4.7, 20.5, and 35.7 percent, respectively. The changes in relative importance of the fuels are shown in figure 8B. Because of its higher price in most parts of the country, oil accounted for only 6.9 to 9.7 percent of the total fuel used until 1969 when its percentage rose to 12.4. Natural gas usage grew from 24.2 percent of the total fuel consumed in 1958 to 30.3 percent in 1969. The use of coal, meanwhile, declined from 67.6 percent of the total fuel in 1958 to 57.3 in 1969. The percentages are for fuels alone and do not include hydroelectric energy.

Figure 9A shows the cost, in cents per million Btu, of fuels at the mine or well, and figure 9B gives the price of fuels at utility plants. At an average well-head cost of 16.1 cents per Mcf in 1968, the cost of natural gas was about 30 percent that of oil, although it is not unusual for both gas and oil to be produced from the same well. In figure 9C the utility fuel price indexes are compared with those of wholesale industrial commodities and of electricity. While the natural gas price index increased 20 percent above the 1957-1959 level, its average cost was still below that of coal in 1968. Despite a 17.5 percent decline, the price of oil remained about 30 percent above those of gas and coal. No specific data are yet available as to the total effects of the significant price increases for fuels that have occurred since the end of 1968.

Natural Gas

About 80 percent of the nation's gas reserves and 79 percent of the annual production occur in Texas, Oklahoma, Louisiana, and Arkansas. Within this area, where only slight costs of transportation from the well head to the electric utility plant are involved, no other fuel can compete. Each thousand miles of transportation costs 12 to 15 cents per thousand cubic feet (Mcf), which is equivalent to about 12 to 15 cents per million Btu.

Gas for residential and other space heating is required principally during the winter months. To utilize transmission pipelines more efficiently, gas companies sell gas during the summer months to utilities and other industrial firms on an interruptible basis. On such a basis, service may be interrupted when the gas is required for uses of higher priority. Interruptible gas is priced at a level sufficiently low to be competitive with other fuels but high enough to cover the direct cost of the gas at the well head and contribute toward the cost of pipeline investment.

Depleted gas and oil reservoirs or other suitable geologic structures have recently come into use for the underground storage of natural gas. Gas available from the pipelines during summer or other times of low demand is held

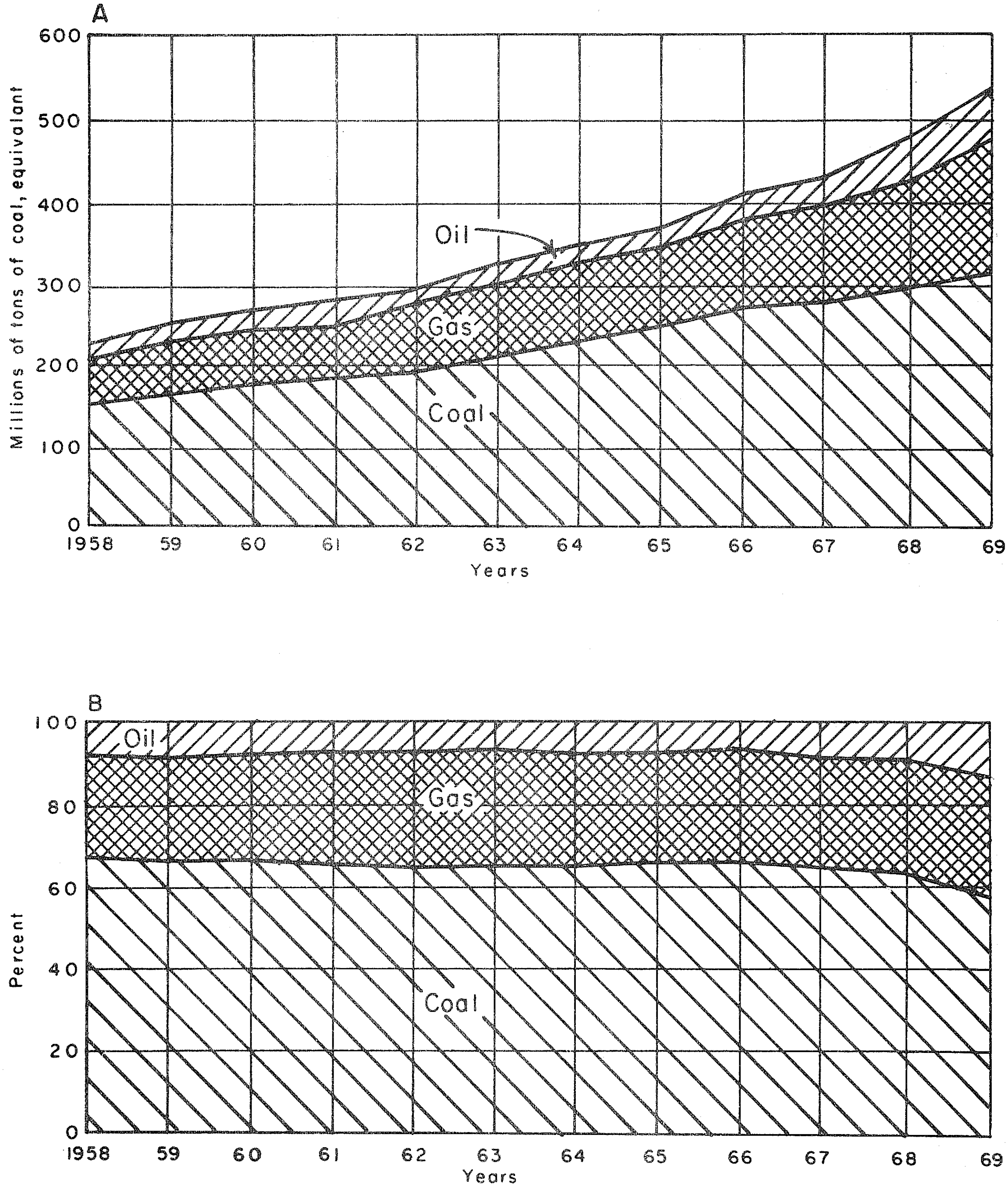


Fig. 8 - Electric utility fuel trends in the United States, 1958-1969. A - Fuel consumed by electric utilities; B - Percentage of fuel energy provided by individual fuels.

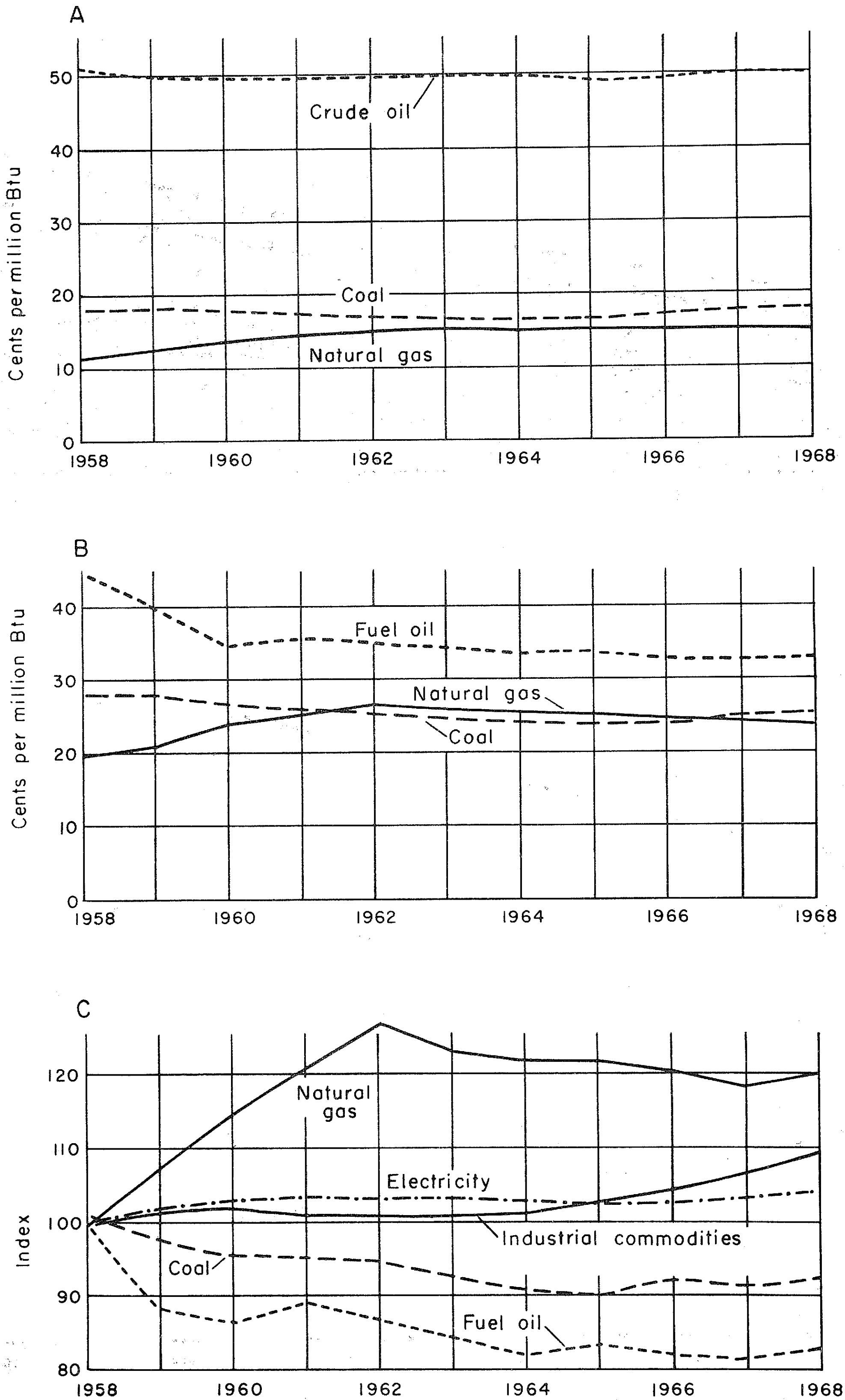


Fig. 9 - Price trends of fuels consumed by electric utilities, 1958-1968.
A - Average United States price of fuels at well or mine;
B - Average price of fuels at electric utility plants;
C - Price indexes of utility fuels, electricity, and industrial commodities.

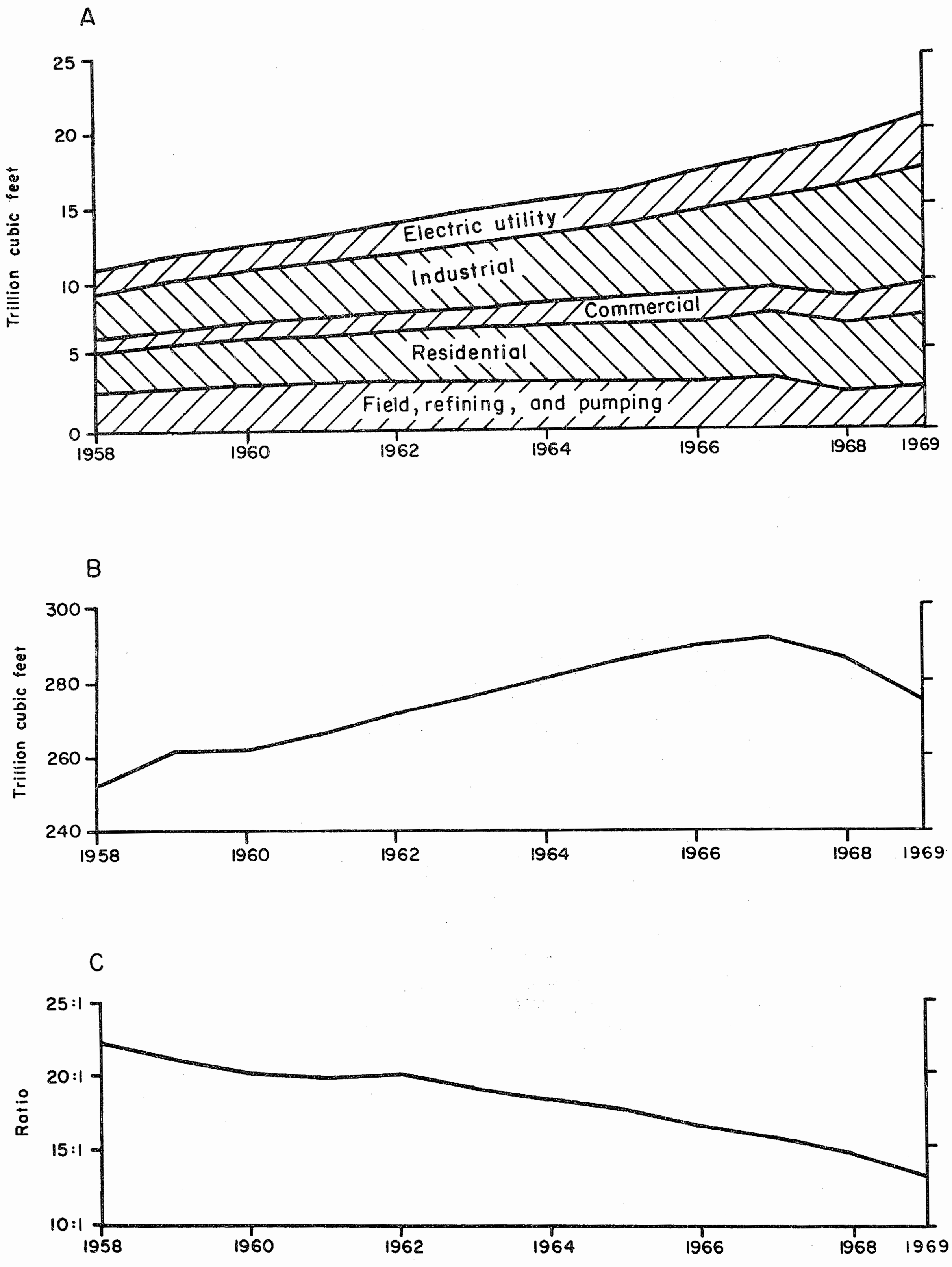


Fig. 10 - Trends in natural gas uses and availability in the United States, 1958-1969. A - Trends in the uses of natural gas; B - Known reserves of natural gas in the United States; C - Ratio of known natural gas reserves to annual production.

in storage for cold weather use. Gas distributors are thus able to serve a larger number of seasonal residential and other heating customers than could be supplied by the pipeline capacity alone. However, the storage plan has reduced supplies of interruptible gas that otherwise would have been available for industrial and utility use. "Firm," or noninterruptible, supplies of gas have been available to these consumers only at a higher cost.

Within recent years electric utilities, especially those operating within large metropolitan areas, have been faced with increasingly stringent regulations on sulfur dioxide emissions from their power plants. Low-sulfur coal and oil are not available in most locations where coal and oil are burned in sufficient quantities to meet the needs. Attempting to turn to gas, many utilities found that gas was not available in sufficient quantities to substitute for oil or coal or to provide for increased power generation.

Figure 10A shows the trends in the net production of natural gas since 1958. In the 11 years shown, ending in 1969, net production rose from 11.4 trillion cubic feet per year to 20.7 trillion cubic feet. Eleven years previously, in 1947, production was only 5.6 trillion cubic feet.

Through 1967, annual discoveries and additions to the reserves exceeded annual consumption, and at the end of 1967 reserves were 293 trillion cubic feet (fig. 10B). In 1968, marketed production exceeded discoveries for the first time. From 1967 through 1969 growing consumption and lower finding rates led to a net decline of 18 trillion cubic feet in reserves. Total reserves fell from 293 trillion cubic feet to 275 trillion cubic feet (41, p. 126).

New discoveries of natural gas are a function of both the amount of drilling and the success of this effort in finding gas. In recent years both the amount of drilling and the success percentage have declined. Table 11 shows that in 1957 out of a total of 8,014 wildcat holes drilled for oil and gas only 872 (10.9 percent) resulted in productive wells. In 1969, only 535 of 5,956 (9 percent) holes drilled were productive.

Shown in figure 10C is the reserve to production (R/P) ratio, which, from the standpoint of availability, or deliverability, of natural gas at any given time, is a more significant figure than total reserves. From 37.5 in 1945, the R/P ratio fell to 22.1 in 1958 and to 13.3 in 1969. A point has been reached at which lack of available reserves is hampering further expansion of output.

The likelihood of a gas shortage in the 1970s was pointed out as early as 1956 in a study that outlined the trends in gas consumption and discoveries (42). This conclusion, drawn almost 15 years in advance of the current shortage, came only a short time after well-head price controls were put into effect and too soon to evaluate the impact of such controls on the availability of gas.

During the 1960s numerous articles appeared, some predicting a natural gas shortage (43, 44) and others denying or doubting the likelihood that such a shortage would occur (45, 46). Most agreed that additional quantities of gas existed. Where they differed was on whether demand would outrun deliverability and what influence price controls would have on availability.

TABLE 11--NEW FIELD WILDCAT WELLS DRILLED IN THE UNITED STATES, 1957-1969

Year	Total wildcats drilled	Total oil and gas producers	Gas producers	Percent successful Total	Percent successful Gas
1957	8,014	872	NA	10.9	NA
1958	6,950	786	NA	11.3	NA
1959	7,031	772	NA	11.0	NA
1960	7,320	745	NA	10.2	NA
1961	6,909	745	316	10.8	4.6
1962	6,794	787	317	11.6	4.7
1963	6,570	769	240	11.7	3.7
1964	6,632	701	252	10.6	3.8
1965	6,182	638	234	10.3	3.8
1966	6,158	635	232	10.3	3.8
1967	5,260	560	189	10.6	3.6
1968	5,205	448	127	8.6	2.4
1969	5,956	535	191	9.0	3.2

NA - Figures not available.

Source: AAPG Bulletin, June issues.

Ultimate volume of gas in the continental United States, including Alaska, was estimated in 1968, on the basis of general geologic evidence, to be as much as 1,859 trillion cubic feet (table 12). This estimate includes 632 trillion cubic feet of undiscovered gas currently classed as "speculative" and 595 trillion cubic feet classed as "probable" or "possible." By the end of 1968, a total of 345 trillion cubic feet had been produced and 287 trillion cubic feet was in known reserves (47, p. 18). By the end of 1969 reserves had fallen to 275 trillion cubic feet.

TABLE 12- NATURAL GAS SUPPLY IN THE UNITED STATES, INCLUDING ALASKA, ON DECEMBER 31, 1968

	Trillion cu ft	Percent
Cumulative production (excluding storage)	345	18.6
Proved reserves (including storage)	287	15.4
Potential gas supply (1,227 trillion cu ft)		
Probable supply	260	14.0
Possible supply	335	18.0
Speculative supply	632	34.0
Ultimately discoverable volume	1,859	100.0

Source: 47, p. 18.

The problem that confronts the nation today with regard to natural gas is that new reserves of natural gas are not being found rapidly enough to support the growth in demand. Either more gas must be found, the growth in demand must be curtailed, or some of the demand for natural gas must remain unsatisfied.

The well-head prices of gas moving in interstate commerce are set by the Federal Power Commission, which was given authority to establish the level of such prices in 1954. Intrastate gas (i.e., gas consumed in the state in which it is produced) is not subject to Federal price regulations and normally sells at a price above the interstate ceilings. Price regulation is intended to protect the consumer from excessive charges for the gas. The prices that have been set have in many cases made gas available at a cost considerably lower than that of other available fuels. Together with the desirable physical characteristics that gas possesses, the low cost has made gas an especially desirable fuel for uses for which other fuels might have served equally well.

From an economic standpoint, the fixing of the price of any commodity at a level below that which would prevail in a free, competitive market can be expected to have two effects: (1) the demand will be increased, especially for those uses in which competition with substitute materials on the basis of cost is a significant factor, and (2) the supply, or availability, will decline.

Statements appearing in an article published in May 1965, dealt with the situation that was developing at the time.

> If past trends in both consumption and new discoveries persist, the reserves will have dwindled to a 13.5 year supply by 1970 and only a 9 year supply by 1975.... The situation poses to the public the question as to whether the public interest will best be served by (a) continued low natural gas prices today with the inevitable shortage to follow in the not-too-distant future or, (b) a higher price for gas today accompanied by the greater assurance of continuing supply in the future.
> (48, p. 10.)

Whether or not some shortage of natural gas would have existed today in the absence of the FPC price controls will never be known. There can be no doubt, however, that low gas prices have had an effect on both the supply and demand, and have contributed to an increase in whatever shortage might otherwise have existed. If additional gas is to be found, greater incentive to explore for gas must be provided.

A staff report of the Federal Power Commission in 1969 noted:

> Evidence is mounting that the supply of natural gas is diminishing to critical levels in relation to demand. There is a compelling need for accurate and current analysis and interpretation of this trend. Prior studies of future natural gas availability have proven to be overly optimistic.
> (49, p. 1.)

The authors of this staff report, after conducting a comprehensive analysis of gas supply and demand, concluded that a new government-industry program was needed immediately to insure continued growth of natural gas service. The basic elements of the recommendations included added exploration incentives, Federal

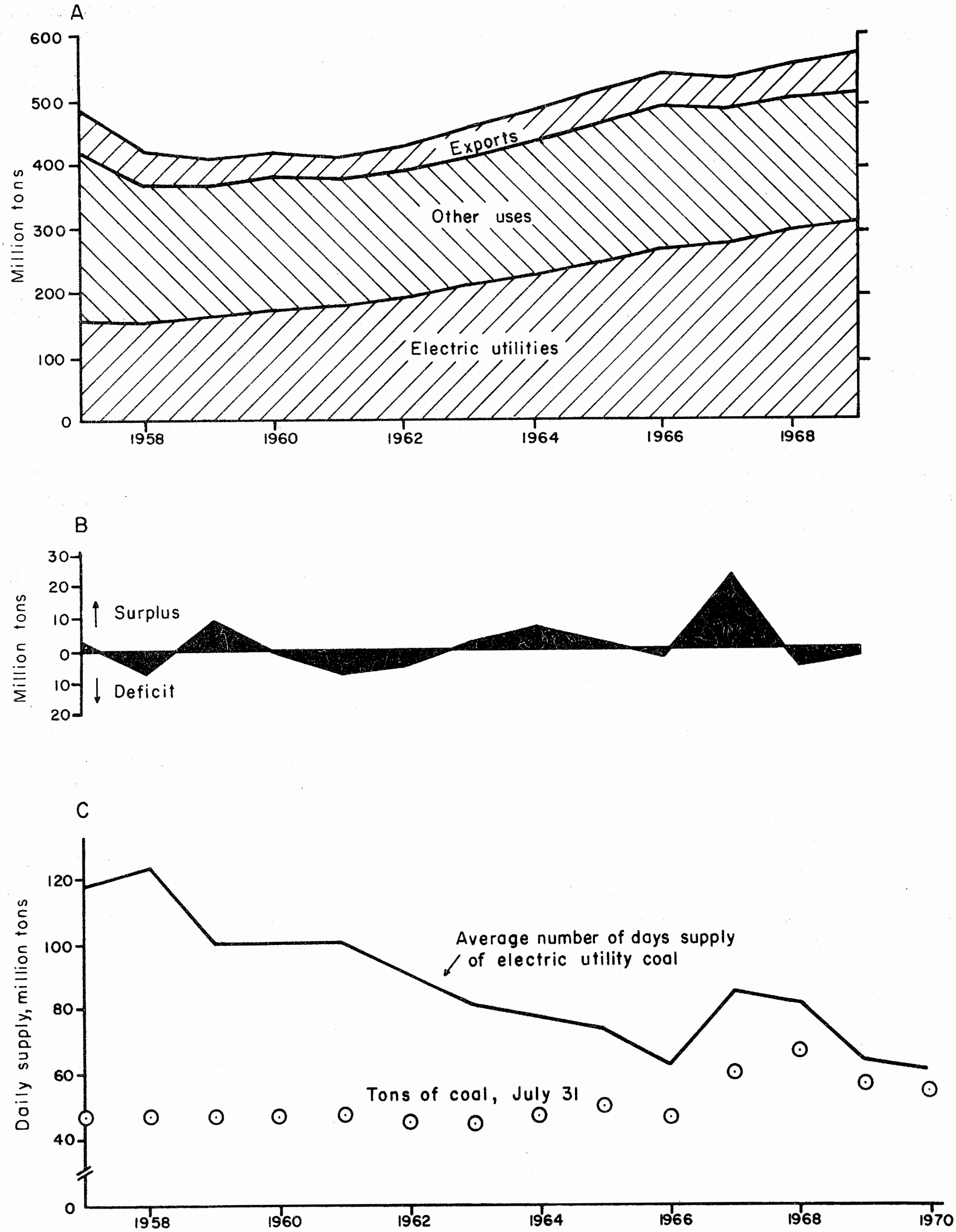


Fig. 11 - Trends in the uses, production, and electric utility inventories of coal in the United States, 1957-1970. A - Consumption and exports of United States coal; B - Surpluses and deficits of production related to consumption of coal in the United States; C - Tons of coal and days of coal supply represented by coal in the hands of United States utilities on July 31.

leasing policies, import policies, use priorities for gas when shortages exist, and expenditures for research and development of synthetic fuels (49, p. 4).

In August of 1970 the staff of the Federal Power Commission recommended rate increases for new gas, ranging from 3.5 to 11.5 cents per Mcf, and basic changes in the rate-making procedures. The proposed price increases were opposed by the public utility commissions of some states and by a number of distributors (50).

There is no way of determining exactly how much effect a given increase in prices will have. The relaxation of well-head price restrictions will result in more drilling and bring additional gas to the market. The most immediate effect on gas supply will be from additional wells drilled to produce more gas from fields already discovered. A significant improvement in the reserves situation in the immediate future is unlikely, however, for new deposits of gas must be discovered. After the discovery of a new gas deposit, it takes an average of about 5 more years to bring a new field into production.

Coal

Coal was the major source of the energy that formed the base for the early industrialization and economic growth of the United States. It was not until 1946 that the consumption of energy from oil and gas combined exceeded that from coal. Table 13 indicates changes that took place in the markets for coal after that date.

TABLE 13—COAL CONSUMED, BY SELECTED CONSUMER CLASS*
(million tons)

Consumer	1947	1957	1967	1968	1969 (est.)
Electric utilities	86.0	157.4	271.8	294.7	308.5
Railroads	109.3	8.4	Negligible	Negligible	Negligible
Coke	104.8	108.0	92.3	90.8	92.9
Other industrial	146.1	102.8	98.8	97.5	92.9
Ship bunkers	3.1	1.4	0.5	0.4	0.3
Retail	96.6	35.7	17.1	15.2	12.7
Domestic consumption	545.9	413.7	480.5	498.6	507.3
Exports	68.6	76.3	49.5	50.6	56.2
Total consumption	614.5	490.0	530.0	549.2	563.5

* Bituminous coal and lignite. Does not include anthracite.
Source: U. S. Bureau of Mines Minerals Yearbooks for years noted.

Figure 11 shows trends in the domestic use and exports of coal since 1957. While use of coal by utilities since 1957 has increased at an average rate of 5.8 percent per year for a total gain of 151 million tons, the combined total of other uses in the United States has declined 57.5 million tons in the 12-year period.

Coal was able to retain a significant share of the utility fuel market because of its availability throughout most of the country and because it has generally been less expensive than other fuels. The energy content of United States coal (bituminous coal and lignite) occurring within the 48 contiguous states has been estimated to be 3.5 times that of all of the other fossil fuels (oil, gas, and oil shale) combined (51, p. 89). As of January 1, 1967, the remaining coal resources in the ground in United States areas already explored and mapped were estimated at 1,570 billion tons, which at 50 percent recovery would provide 780 billion tons of coal (52, p. 11). An additional 1,313 billion tons has been estimated to exist in areas not yet fully mapped or explored. Current production of coal in the United States is somewhat less than 600 million tons per year.

The coal of the estimated reserves includes all varieties, ranging from high grade bituminous with a heat value of more than 15,000 Btu per pound to lignite that contains 45 percent moisture and has a heat value of less than 7,000 Btu (53, p. 78).

Coals also vary widely in chemical make up. Sulfur content, which has become a critical factor in coal selection, generally ranges from less than 0.5 percent to over 6 percent. However, the sulfur content in an individual coal may vary greatly within a given area. The principal regions of low-sulfur coal are the southern Appalachian bituminous coal fields and the northern Rocky Mountain and Great Plains sub-bituminous and lignite fields.

In the past, the major use for low-sulfur coal (i.e., coal containing 1 percent or less sulfur) was in the manufacture of metallurgical coke. Of the 507 million tons of coal consumed in 1969, 92.9 million was used for this purpose (19, p. 6). Most of the coal exported to foreign nations also is coking coal (54, p. 69).

Much of the low-sulfur coal in the eastern United States is owned or committed by contract to steel producers. This situation results from their need to provide for their long-term requirements of high grade coking coal.

In 1964, the last year for which complete data on low-sulfur coal production are available, an estimated 185.4 million tons was produced, of which 19.4 million came from the far west and 149.2 million from coal mining districts that are located within eastern Kentucky, southern West Virginia, Virginia, and a corner of Tennessee. All the rest of the nation produced only 16.8 million tons (54, p. 68).

Low-sulfur coal constitutes an indeterminate but minor share of total reserves, is limited geographically in its occurrence, and in the areas east of the Mississippi generally commands a premium price. For these reasons it has been used to only a limited degree as utility fuel, except where it is indigenous to the area. An article published in 1966 indicated that 90 percent of the coal consumed by utilities contained more than 1 percent sulfur and 95 percent contained more than 0.7 percent sulfur (55, p. 58).

For utilities located outside the low-sulfur coal areas, the acquisition of low-sulfur coal to comply with air-pollution regulations has been especially difficult. Additional low-sulfur coal is, in general, not available from existing mines, and the construction of new mines generally requires 2 to 4 years. The construction of a new modern mine also requires a 20- to 30-year reserve of recoverable coal, an investment of about 10 dollars per ton of annual capacity, a work force of 150 to 200 men per million tons per year of output, and, generally, a long-term purchase commitment to justify the investment.

For power plants outside the low-sulfur coal areas, a transfer to low-sulfur coal also means increased transportation costs. Such costs increase a minimum of about 50 cents per ton for every 100 miles of distance added from mine to plant.

Low-sulfur coals are, in many instances, premium coals that command a higher price than ordinary steam coals. If low-sulfur utility coal is obtained from areas that now sell most of their coals for coking, the utility companies must meet the coking coal prices, which are generally higher than those for steam coals. In 1968, before the current coal shortage, the price per ton of coal delivered to coke plants in West Virginia was $8.00, while the steam coal delivered to utility plants within the state averaged only $5.27. In Illinois, coking coal was delivered that year at $9.73 per ton and utility coal at an average of $5.10 per ton. The reported average of coking coal delivered to plants in northern Indiana was $10.68 per ton, whereas the coal used by major power plants in the same area ranged from $4.24 to $5.68 per ton.

Much of the low-sulfur coal of the Rocky Mountain region is noncoking, is easily mined, and may be purchased at lower prices than low-sulfur coal from the eastern coal fields. However, the distance from these coal reserves to the major coal-consuming areas of the United States, combined with their generally lower heat content and the additional quantities of coal required to furnish equivalent amounts of energy, largely offset the initial price advantage they possess and make them costly to use outside their own region.

Although low-sulfur coal, except in the areas of its occurrence, has never found widespread use as utility fuel because of its cost and restricted availability, other types of coal have been generally available and the total use of coal by utilities has grown rapidly, as shown in table 13 and figure 11A. In 1968, however, despite the large reserves of coal that exist, the demand for coal for domestic and export purposes outran production, a situation that was repeated in 1969 and is occurring again in 1970.

Figure 11B shows the annual surpluses and deficits between coal production and consumption. The deficits in 1968 and 1969 were made up from inventory stocks on hand from earlier years. Shown in figure 11C are the stocks of coal on hand at power plants on July 31 of each year. The actual total tonnages on hand have not declined below those of earlier years, but, because of greater usage, the stocks in terms of days' supply have dropped significantly. The coal stocks on hand at utility plants on July 31, 1970, were 54.8 million tons, which represents a 62-day supply (56, p. 5). To reestablish the level of an 85-day supply that existed on July 31, 1967, would require an addition of 20.3 million tons (37 percent) to the stocks. Since stocks are not evenly distributed among the various consumers, the coal available to some consumers has been reduced to only a few days' supply. In mid-August 1970, TVA's coal inventories were reported to be down to a 10- to 12-day supply, less than 2 million tons, compared with the 6.5 million tons they had on hand just 2 years earlier (57).

The 1970 bituminous coal production through September 12, 1970, was reported to be running 20.8 million tons above the 1969 output for the same period (58, p. 1). However, coal consumers of all kinds were still encountering difficulty in obtaining coal. Estimates in mid-September indicated that the total production for 1970 might run 10 million tons behind the estimated demand (59).

The demand for United States coal for domestic consumption and exports rose from 490 million tons in 1957 to 563 million tons in 1969 (table 13 and fig. 11A). Production rose from 493 million tons to 560 million tons during the same period. Demand during 1970 is estimated at 580 million tons (59), and production is projected at 570 million tons. Figure 11B shows the annual deficits and surpluses between production and consumption. Deficits occurring in 1968 and 1969 were 4 million tons and 3 million tons, respectively (58, p. 4). Earlier estimates had indicated a 1969 deficit of 7.5 million tons (2, p. 5). If the projected 10-million-ton shortfall for 1970 does materialize, total consumption will have exceeded output by about 17 million tons for the 3-year period ending December 1970. The deficit has been met only through a reduction of inventories below the level of 1967.

Several factors have contributed to the United States shortage of coal, among them the rapid growth in demand discussed above, the failure of existing mines to operate at full capacity, and a lag in the construction of new mine capacity. The failure to operate at capacity resulted from work stoppages, lack of railroad cars in which to transport the coal, and a shortage of manpower.

The past year or two has been a period of considerable labor unrest, resulting in numerous work stoppages. Wildcat strikes were reported to have cost 626,505 man-days and more than 12 million tons of output during 1969 (60). Additional time was lost through strikes in 1970. Only one month in the 18 months prior to March 1970 was estimated to have been completely free of strikes (61).

At most mines the coal goes directly from the mine, through the preparation plant, and into railroad cars. With very limited storage space at the mine, a lack of cars will quickly shut down the mine. Not only is there a reported lack of cars in sufficient numbers, but there is a problem of getting cars to the right place at the right time because the return of empty cars is delayed (60). Both of these factors result in losses in production.

The lack of basic production capacity is a problem that must be overcome if the nation's future energy needs are to be met. The shortage of manpower and losses of some capacity through closure of mines on the basis of inability to comply with new safety laws have caused some reduction in capacity (60). More fundamental is the fact that new mines have not come into operation at a rate fast enough to keep pace with demand.

New mines coming into production to meet the growing demands of the 1968-1970 period would have had to be planned and construction started in the mid-1960s. At that time, two events occurred that made it questionable whether coal could compete for the future utility market and made operators consider carefully whether expenditures for new coal mines would be a good investment. First, the low estimated cost of nuclear power made it questionable whether coal could continue to compete in the utility market. Second, the proposed sulfur emission standards made it doubtful whether the average coal could remain

TABLE 14—CONTRACTS FOR NUCLEAR POWER PLANTS

Year of contract award	Number	Capacity, megawatts
1953 - 1964	16	4,313
1965	7	4,267
1966	20	16,044
1967	31	25,780
1968	17	15,642
Through 9/30/1969	4	3,869
Total as of 9/30/1969	95	69,915

Source: 24, p. 133.

acceptable as a fuel throughout most of the country. As a result, not only the future but the present markets for coal were endangered.

In 1963 the decision of the Jersey Central Power and Light Company to construct the Oyster Creek Nuclear Plant was announced. This plant was expected to produce electric power from nuclear fuel at a cost 23 percent below costs for conventional fuels (62). The estimated cost of nuclear-generated power was to be equivalent to that of power from a coal-fired steam plant having a coal fuel cost of 20 cents per million Btu. As it turned out, the plant, scheduled for operation in 1967, encountered numerous delays and was not ready for operation until 1969. True costs still have not been determined.

In 1965, the Tennessee Valley Authority announced plans for construction of the Brown's Ferry Nuclear Plant, to be operational in 1970. Estimates of total costs of producing power with the TVA plant ranged from 2.39 to 2.56 mills per kilowatt hour produced. This compared to an estimate of 2.90 mills per kwh for a conventional coal-fired plant with coal costs at 18.9 cents per million Btu (63). To match the lower (2.56 mill) total power cost estimate, coal costs would have had to be reduced to about 15.1 cents per million Btu. Of the 487 electric utility power plants of all sizes using coal in 1965, only 9 reported coal costs of less than 16.0 cents per million Btu (64).

Although an actual comparison of true costs and estimated costs of these two power plants was not possible then and still will not be possible for some time, the forecasts were sufficiently optimistic to cause a flurry of interest and were quickly followed by the ordering of a large number of nuclear plants. The number of contracts for new nuclear plants grew and then quickly subsided, as shown in table 14. By the end of 1969 only 4,271 megawatts of capacity were actually in operation. The status of all nuclear plants as of December 31, 1969, was as follows (65):

Status	Number	Capacity, kilowatts
Operable	16	4,271,700
Being built	48	38,455,200
Planned (reactors ordered)	34	30,883,000
Planned (reactors not ordered)	8	7,645,000
		81,254,900

The delays encountered in the construction of nuclear plants, and the reasons, have been discussed earlier. As construction of nuclear plants lagged, it became necessary to build fossil-fuel plants to meet the demand for power, because they could be constructed much more quickly.

About the same time that the rush toward nuclear plants on the promise of lower cost was occurring, coal came under another serious attack because of its contribution to air pollution from sulfur dioxide.

Early in 1965, the Bureau of the Budget instructed all federal agencies to follow new guidelines in the purchase of fuels for government installations. The guidelines, established by the Department of Health, Education and Welfare (HEW), set sulfur dioxide emission standards that, in effect, could be met only by coal containing no more than 0.75 percent sulfur. These standards were to apply to all government installations in New York, Chicago, Philadelphia, and Los Angeles, and to all other installations with heat inputs of less than 10 million Btu per hour (66). Municipal and state agencies also began to establish regulations (some had already done so) that would prohibit use of coal containing more than a given amount of sulfur. In most cases the maximum was initially set at about 2 percent, with proposals for further reductions to the range of 1 to 1.5 percent sulfur within another 2 or 3 years.

To comply with sulfur restrictions that made most traditional coal sources unacceptable, utilities have tried to obtain substitutes. A Chicago utility, unable to obtain sufficient additional low-sulfur oil or natural gas supplies to substitute for local coal of higher sulfur content, purchased coal from Wyoming and Montana (67). Transportation distances of about 1200 miles are involved for this coal, compared to 300 miles or less for coal from Illinois. Furthermore, because of its lower heat value more of the western coal is required to provide the same energy, and its different burning characteristics cause combustion problems.

Research has been under way for a number of years to find a suitable means of reducing or eliminating sulfur dioxide emitted from coal-fired power plants. Efforts aimed at the reduction of sulfur dioxide produced during the combustion of high-sulfur coals have included several approaches:

1) Improvement of coal preparation techniques to remove more of the sulfur from the coal before combustion.
2) Use of limestone or dolomite, or other additives, in the furnace to tie up chemically the sulfur released during combustion.
3) Use of wet or dry processes for removal of sulfur dioxide from the stack gases.
4) Development of "fluidized bed" or other new types of combustion equipment and processes.
5) Conversion of coal to low-sulfur gas through hydrogenation.
6) The solvent refining of the coal material to form a new low-sulfur fuel product.

The results that can be attained through coal preparation are limited. The sulfur that occurs in discrete particles of pyrite can be partially removed in normal coal preparation by gravity or flotation techniques, although in many cases not more than half of such sulfur is removable. Furthermore, nonpyritic "organic" sulfur, often constituting half or more of the total sulfur, cannot be removed by any known physical means of coal preparation. Thus, for many of the coals that are available, normal coal preparation will not produce satisfactory results.

Extensive research is being done on the removal of sulfur by additives and on the cleaning of stack gases. A number of full-scale tests are being made or planned, and some of the processes should be fully proved as economically feasible by the mid-1970s or sooner. Other research is being devoted to new combustion equipment and processes.

Pilot-scale experiments are being conducted to determine whether coal gasification processes are feasible and competitive. Current estimates indicate that synthetic gas could be produced at costs equal to, or only slightly above, those for natural gas in some parts of the country (68, p. 63).

During the current coal shortage, the price of coal has risen sharply, creating an especially difficult situation for small consumers who must purchase fuel in small quantities at spot market prices. Most utilities purchase fuel on long-term agreements to assure an adequate supply at a contracted price, but some utilities that rely on short-term bids to fill part of their requirements have been significantly affected by the price rise. The larger quantities of lower cost coal received under long-term contracts do, however, help to minimize the impact of smaller purchases at high spot prices.

Reports indicate that TVA, which paid $4.00 to $4.50 per ton a year ago, was for a time having difficulty in procuring coal even at prices as high as $9.00 per ton in mid-1970 (69, p. 71). In October, however, TVA announced purchase of 3.9 million tons at $5.77 per ton (70). The TVA Annual Report issued in late 1970 estimated the average fuel cost for 1970 at 20.35 cents per million Btu, compared to 19.22 cents in 1969 (17, p. 41).

Oil

In 1968, electric utilities consumed 171.9 million barrels of oil, 86.6 percent of which was consumed by utilities in states along the eastern seaboard (30, p. 51). Of the total fuel oil they used, more than 98 percent was residual, most of it imported from foreign sources. The low cost of residual oil, historically about one fourth the cost of distillate fuel oil, made it especially attractive for utility use. The extent of the east coast's dependence on foreign imports is demonstrated by the fact that from January through May of 1970 93.7 percent of the residual fuel oil used by eastern seaboard consumers came from overseas sources. Residual fuel oil contributed about 45 percent of the energy used for industrial and commercial purposes on the east coast in 1969 (71).

Because residual oil brought such a low price, United States refiners generally have extracted the maximum amount of gasoline and other higher value products from the crude oil, reducing the output of low-value residual to a minimum. In 1968 residual oil constituted only 7.2 percent of total refinery output of the United States, compared to 22.1 percent in 1948 (72, p. 876; 73, p. 959). In the same years, gasoline rose from 40.3 to 43.9 percent and distillate fuel oil from 18.7 percent to 22.1 percent of total output. To provide additional supplies of residual and other fuel oils, the nation's refiners plan to increase the output of these products during the winter of 1970-1971. In the process, of course, the supply of gasoline will be reduced (74).

Much of the residual oil produced by refineries within the United States, and part of the foreign oil also, exceeds the sulfur emission limits set in many areas of the country today. Methods of desulfurization are available, however, at costs estimated at about 1 to 1½ cents per gallon. Desulfurizing plants are already in operation both here and abroad, and additional plants are being constructed (20, p. 47).

There appears to be little or no likelihood that the United States will ever again become completely self-sufficient in oil. Not since 1947 has the nation supplied its requirements wholly from domestic sources. Oil from the large discoveries in the Alaskan North Slope area will assist the nation in meeting its requirements, beginning in the latter half of the 1970s. Despite the huge size of these reserves, they are likely, by the time they become available, to provide for only part of the growth in demand for oil in the United States, rather than actually reversing the present trend toward greater dependence on foreign oil.

Nuclear Fuel

At the present time there is no shortage of uranium to fuel nuclear plants. Recent announcements by nuclear fuel suppliers indicate that utilities are requesting a delay in delivery of fuel already contracted for (75). The current surplus is caused by delays in the construction of the nuclear plants that are scheduled to use it, and so may be considered as temporary in nature. No supply problem is anticipated, however, in the next several years.

The adequacy of uranium reserves to meet long-term future needs will depend primarily on the rate of growth of nuclear power and the success in developing the breeder reactor or a controlled fusion process.

Various estimates have been made of the growth rate that can be anticipated in nuclear plants. Despite the recent slow-down in nuclear plant construction and decrease in new orders for nuclear power plant equipment, nuclear capacity of 150,000 megawatts is still expected in the nation by 1980 (76, p. 2). Cumulative requirements for uranium (U_3O_8) to power these plants through 1980 have been estimated at 208,000 tons (25, p. 31). To provide fuel for actual use and to establish adequate reserves of fuel to assure continuing operation of these plants, an additional total requirement of 600,000 tons will be needed by 1980 (25, p. 35). By early 1970 doubts were increasing in some quarters as to whether these projected fuel needs could be met (77, p. 84). Estimates of reserves of uranium available in the United States in 1968 at prices up to $8.00 per pound were 160,000 tons (25, p. 35) and at prices up to $10.00 per pound were 310,000 tons (78, p. 53).

Research has been under way for a number of years to develop a breeder-type reactor that will produce additional fuel at the same time that power is being produced. Atomic Energy Commission spokesmen have predicted that breeder reactor research will be successful and that such plants will be operational by the mid-1980s. When this happens the adequacy of uranium supplies should be assured, for the new fuel requirements will be small enough that fuel cost will no longer be an important factor.

Should breeder research fail, or should delays be encountered that are proportional to those that have confronted the fission reactors so that breeder reactors are not available by 1990, significant problems of atomic fuel supply may develop (79, p. 27). Reserve and demand estimates indicate that not only could a shortage develop that might retard further growth of nuclear plants, but fuel might not be available at acceptable costs for plants that will already be in existence.

Success with the controlled fusion process, on which research also is being done, would eliminate problems of future nuclear fuel supplies, but estimates have been made that fusion power may not be available before the year 2000 (79, p. 28).

Environmental Problems of Fuel Supply

In addition to the environmental problems associated with the utilization of the various fuels, some problems of an environmental nature also are encountered in their production.

In coal mining, commonly occurring environmental problems are those related to the disturbance of land surface by strip mining, the drainage of acid water from underground or surface mine areas, and the subsidence of the surface above underground mines. These problems have received considerable attention at both the Federal and state levels, and legislation exists in most major coal mining states that requires reclamation of surface-mined land (80, p. 99).

The brines brought to the surface in the production of oil presented an environmental problem in the past, but the brines are now reinjected into the earth through disposal wells.

Within the past few years, oil spills in the Santa Barbara Channel and the Gulf of Mexico have called to the attention of the public an environmental problem connected with the drilling for and production of oil and gas. It is to be hoped that strict compliance with the procedures that have been developed will effectively control this problem. The banning of further offshore drilling, as has sometimes been suggested, would have a heavy impact on the nation's future ability to meet the demands for fuel. An estimated 12.8 percent of the United States reserves of gas and 9.3 percent of the oil reserves now known are in offshore locations in the Gulf of Mexico (41, p. 120; 41, p. 27). Complete prohibition of further offshore drilling would not only make this oil and gas unavailable but also eliminate the possibility of discovering additional supplies in vast offshore areas that have not yet been tested by drilling.

Environmental considerations also are delaying construction of the Trans-Alaska Pipeline, which will postpone the day when Alaskan North Slope oil will become available to help meet the nation's oil requirements. Plans have been made for constructing an 800-mile, 48-inch pipeline to transport the oil from northern Alaska to Valdez on the southern coast of Alaska. For a considerable part of the distance, the pipeline route crosses permanently frozen ground (permafrost). The disturbance and exposure of the permafrost may result in a long-term modification of surface conditions that will be extremely difficult to control. Permission for the construction of the pipeline has been postponed until thorough studies of the ecological effects of both the pipeline construction and the passage of warm oil through the line can be completed and procedures developed for preventing or minimizing the damage that might occur. Quantities of 48-inch pipe are already on hand in Alaska, ready for movement to the pipeline site as soon as authorization to begin construction is received (81, p. 106). Until authorization can be granted or some other means of moving the oil is developed, these oil reserves, now estimated at from 12 to 15 billion barrels but potentially much more, will remain unavailable (81, p. 116).

Studies also are being made on the possibility of moving natural gas from the North Slope to the Midwest (81, p. 142).

Certain special hazards exist in connection with the underground mining of uranium ore and the disposal and use of waste material or "tailings" resulting from the milling of the ore. The tailings contain traces of radioactivity. Reports have been published indicating a statistically unusual frequency in the occurrence of lung cancer in miners who have worked in uranium mines. This is attributed to exposure to concentrations of radioactive radon gas within some of the mine workings. A recent report by the U. S. Bureau of Mines deals extensively with means of reducing and controlling the hazard (82).

SUMMARY AND CONCLUSIONS

The United States is at present confronted with serious shortages of both electric generating capacity and fuels. These shortages will continue to exist for some time and will be overcome only by the development of new capacity requiring both time and large expenditures of capital.

The shortage of generating capacity is the result of a very rapid growth in demand for power and delays in construction of new capacity. The delays result from (1) difficulties in manufacturing and fabricating equipment, and (2) public opposition, most of it from people concerned about detrimental effects on the environment. Principal objections arose from public fear of nuclear hazards or catastrophes, concern for water and air pollution, and desire to prevent the changes that would result from the damming of streams and other modification of the landscape, especially in recreational or scenic areas.

Shortages of fuels resulted from a low level of drilling activity in search of natural gas, a declining resource base in oil, and insufficient production of coal caused by lack of mine capacity and by interruptions in production at existing mines.

Completion of the power plants already scheduled and under construction will go a long way toward relieving the present shortage of capacity. However, additional new electric generating capacity in ever-increasing quantities will be required to keep pace with growing demand. Stricter regulation of plans for the siting of future plants can be anticipated, but this should, at the same time, eliminate some of the delays and uncertainties that now exist.

No very significant increase in the use of natural gas as a utility fuel is likely in the future. Even when prices are raised sufficiently to promote additional drilling and new gas is found, several years will be required before full production can be attained. The demand for gas for other uses will limit its availability for utility use, and the increased price and other costs will make it uneconomical as a utility fuel in most locations. Higher prices, however, in addition to bringing more gas on the market, may also make it economical and practical to supplement natural gas supplies with gas manufactured from coal.

More coal mine capacity will be developed, and larger quantities of coal will be produced to meet the growing need. However, until satisfactory processes for controlling sulfur and perhaps other emissions from coal are developed and proved economical, producers will be somewhat reluctant to open new mines, and utilities will hesitate to commit themselves to long-term contracts for fear that they may have an unwanted or outlawed product after the current supply situation of other fuels has improved. The recruitment and training of additional manpower for expanded coal production also will be an increasing problem (83).

The nation will continue to depend on other sources of liquid fuel to supplement the domestic crude oil supply. Some of the oil will be imported, but oil from domestic shale and liquefied coal are also likely supplements.

The costs of nuclear plants have escalated considerably, and most plants will exceed the earlier cost estimates that made them appear so much more economical than coal. The high spot market prices for coal now prevailing will decline somewhat when the present shortage is over. However, increased wage rates, the costs involved in complying with stricter safety laws and more stringent land reclamation standards, and costs of sulfur emission control will combine to make the use of coal for power generation more expensive than formerly. Reports published in 1970 estimated that compliance with new mine safety laws might add as much as $1.50 to $2.50 per ton to the cost of utility coal within the next two years (84, p. 46).

If the present timetable for the breeder reactor is kept, or a rapid breakthrough occurs in fusion power, the predicted major role of nuclear energy in helping to provide for the nation's growing electric power needs is assured. If not, a costly and perhaps critical nuclear fuel problem may arise that could retard the growth in the use of nuclear energy and greatly increase the need for using coal.

The development of emission control devices will make it possible to meet high air quality standards and still provide whatever electric energy is required. Until that time, however, the lack of adequate low-sulfur fuel will limit the rate at which strict sulfur emission standards can be applied to many parts of the nation (85). The only alternative will be a curtailment of power production.

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