Electric Power Supply and Demand 1979-1988 for the Contiguous United States

*As Projected by
the Regional Electric Reliability Councils
in Their April 1, 1979
Long-Range Coordinated Planning Reports
to the Department of Energy*

MASTER

October 1979

Published December 1979

U.S. Department of Energy
Economic Regulatory Administration
Division of Power Supply and Reliability

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Microfiche: \$3.00

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Norton Savage, P.E.
William Graban, Chief
Power Supply Planning Branch

U.S. Department of Energy
Economic Regulatory Administration
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Washington, D.C. 20461

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June 30, 1979

Contiguous United States
Electric Power Supply and Demand 1979-1988
As Projected By The Regional Electric Reliability Councils
In Their April 1, 1979 Reports To
The Department of Energy

I. SUMMARY

The Regional Reliability Council ^{1/} projections of growth rates for peak demand, generating capability and electric energy requirements for the contiguous United States have again declined from those made in the previous year. On the basis of these projections, it appears that the electric utility industry still believes that the United States will experience smaller annual increases in electric power use than have occurred in the past. For the contiguous U. S. as a whole, the current reports project the following:

	<u>Average Annual Increase</u> <u>Percent</u>
Summer Peak Demand, 1978-1988	4.9
Winter Peak Demand, 1978-79 to 1988-89	4.9
Annual Net Energy Requirement, 1978-1988	4.8
Capability at Time of Summer Peak, 1978-1988	4.1
Capability at Time of Winter Peak, 1978-79 to 1988-89	4.2

Projected increases in annual energy requirements, peak demand and generating capability vary from council to council. The largest ten-year average growth rates are reported by SWPP, as shown in the table below. Growth projected for energy and peak demand in the ECAR, MAAC and NPCC Council regions is less than in other regions of the U. S.

^{1/} See Appendix A for a discussion of the Reliability Councils and maps showing their areas.

Regional Council Projected Growth Rates
1978-1988

<u>Council</u>	<u>Average Annual Percentage Growth 1978-1988</u>		
	<u>Net Energy</u>	<u>Summer Peak Demand</u>	<u>Net Dependable Capability (Summer)</u>
MAAC	3.5	3.3	2.9
NPCC	3.5	3.4	2.3
ECAR	4.5	4.4	3.9
MAIN	4.7	4.8	3.8
WSCC	4.8	5.0	4.6
SERC	4.8	5.7	5.0
ERCOT	4.9	5.2	3.8
MARCA	5.5	5.6	4.1
SWPP	6.2	6.0	5.6

From summer 1978 to summer 1988, the net dependable generating capability of the contiguous United States is projected to increase by 264,800 MW (Table 3) and the summer peak demand is projected to increase by 244,434 MW (Table 2). The reserve margin will increase by 20,366 MW (Table 4). As a result of the projected demand increases and planned additions to capacity, there will be a decrease in the percentage reserve in each region and for the total U. S. For the U. S. as a whole, the margin is estimated to have been 33.59 percent in summer 1978, and is expected to be about 23.97 percent in summer 1988 (see Table 4). On the basis of historical experience, the projected margins appear adequate to provide reliable electric service under normal conditions during most of the period, in all Council regions except MARCA.

In the MARCA region, the reserve margin at the time of summer peak demand is less than desirable from 1984 on, and in 1987 and 1988 drops to levels well below the magnitude needed for reliable service. Capacity transfers into MARCA from MAIN and SWPP, and the dropping of

interruptible load, may yield some measure of relief from excessively low reserves but do not appear sufficient to assure reliable service. In MAIN, from 1986 on, the summer reserve margins approach the low end of the 15% to 25% range usually considered adequate, as they do in SWPP in 1987 and 1988.

Attainment of the prospective margins of course implies completion of all planned generating units as currently scheduled, and peak demands no larger than currently estimated. Reliability of service will also depend on completion of all planned transmission facilities, adequate fuel supply of the necessary quality and careful attention by utility managements to continuing improvements in design, planning and operating practices. Continuing difficulties in keeping nuclear unit schedules on target, caused by delays in licensing and construction, are a cause for concern. Failure to have nuclear units in operation as scheduled results in a decreased reserve margin and in the consumption of additional fossil fuel. A 1000 MW nuclear unit, in its first full year of operation could displace approximately about 8.8 million barrels of oil (equivalent to an average daily displacement of 24,110 barrels). Section V of this report discusses the need for generating capacity and reserve margin.

II. INTRODUCTION

This report summarizes and reviews information concerning bulk electric power supply and demand for the contiguous United States as projected for the period 1979-1988. For the most part the data are abstracted from the April 1, 1979 Coordinated Bulk Power Supply Programs filed with the Department of Energy by the Regional Electric Reliability Councils.^{1/} Approximately 98% of the electric load and power supply of the contiguous United States is represented in the data furnished by the Councils. The remainder, which consists mostly of small municipal utilities (in some instances not interconnected with any other systems), is not considered to significantly affect bulk power supply in the U.S. as a whole. In this report all references to "Total U.S.", "U.S. Power System", "Contiguous U.S.", refer to the data supplied in the Council reports, unless otherwise noted.

Electric utility power supply systems are composed of power sources, transmission and distribution facilities and users of electricity. In the United States there are three such systems of large geographic extent that together cover the entire country. Largest of the three, and possibly the largest in the world in terms of generating capacity and load, is the 7-Council Interconnection, which covers all or part of 39 states and 3 Canadian provinces. All data and discussion in this report refers only to U.S. loads and facilities. Of the seven Regional Council areas which comprise this network (ECAR, MAAC, MAIN, MARCA, NPCC, SERC, SWPP) three are interconnected with Canadian systems. These three are ECAR, MARCA, NPCC. Interconnection among utilities in this large area has progressed to the point where capacity and energy in significant

^{1/} See Appendix A for General Description of the Regional Electric Reliability Councils

amounts can be routinely exchanged among systems for economic purposes, for emergency purposes, and for other reasons.

The next largest network is a single Council Region, the Western Systems Coordinating Council (WSCC). It covers all or part of 13 western states and extends into the Canadian province of British Columbia. All data and discussion herein refer only to the U.S. portion of WSCC. Within WSCC there are many inter-utility connections but there is only minor power transfer capability between WSCC and other Council areas.

The smallest of the three networks is ERCOT, which covers a large part of the state of Texas. ERCOT utilities are interconnected within Texas but have no interconnections with systems in any other state, nor are they interconnected with those Texas systems, not in ERCOT, that are part of an inter-state system.

Appendix B sets a frame of reference for the council projections of electric power supply by summarizing the approximate composition of U.S. generating capacity as of the end of June 1979.

III. ENERGY FORECASTS

The Reliability Council projections of net annual energy requirements, extending through 1988, are summarized in Table 1. For the nine individual council regions, the average annual growth rate for the decade 1978-1988 ranges from the 3.5 percent projected by MAAC and NPCC to the 6.2 percent estimated by SHPP. Total U. S. electric energy needs are projected to increase at an average annual rate of 4.8 percent. A review of previous energy projections by the Councils shows that their estimates have been declining for some time. As an illustration, the table below shows the totals of the projections on an average annual basis made by the Councils, in the years 1976 through 1979, for the year 1985.

<u>Council Projections made in</u>	<u>Total U.S. Net Energy for 1985 (Gwh)</u>	<u>% Reduction From Projection of Preceding Year</u>
1976	3,486,671	-
1977	3,369,370	3.36
1978	3,237,578	3.91
1979	3,097,389	4.39

Ratio of 1979 projection to 1976 projection = 0.8878

The use of electric energy is of great interest to electric utilities, to government, to those concerned with the environment and to economists, among others. One reason for this interest is the close relationship between use of electric energy and the use of fuel. Except for the electric energy produced by hydroelectric and geothermal plants, totalling

approximately 10 percent to 13 percent of the amount produced by all sources in the last several years, electric energy in the United States is generated by plants using fossil and nuclear fuel sources. Preliminary data for electric utility power generation by fuel type, in the contiguous United States, are shown in the table below for the year 1978:

1978 Net Electric Utility Generation ^{1/}

<u>Source of Electric Energy</u>	<u>Gwh</u> ^{2/}	<u>% of Total</u>
Coal	976,634,621	44.3
Oil	364,202,675	16.5
Gas	305,379,534	13.8
Nuclear	276,403,070	12.5
Hydroelectric	280,579,199	12.7
Other	3,315,601	0.2
Total	2,206,514,700	100.0

^{1/} Department of Energy, Energy Information Administration Energy Data Report DOE/EIA-0049/78 dated May 9, 1979: Power Production, Consumption and Capacity - Annual. (Based on FPC Form 4 Reports)

^{2/} 1 Gigawatthour (Gwh) = 1,000,000 Kilowatthours (kwh)

The use of electric energy is of great concern in respect to fuel requirements because a reduction of electric energy use translates almost proportionately to a reduction in the use of related fuel. Attendant upon a reduction in fuel use, especially in the use of fossil fuel, is a reduction in the stress upon those natural resources used to produce fuel and upon the facilities used in fuel production and transportation. There is also less stress upon the environment, both in the obtaining of fuel and in the disposal of waste products. However, it is believed that a close relationship may exist between the use of electric energy and the national economic health. Over the long term, the use of electricity and the gross national product have appeared to increase together. Therefore a decreasing rate of electric power growth may stem from a decreasing economic growth rate. On the other hand, greater efficiency and wisdom in the application of electric power may allow lesser use without a decline in the economy. This area is one which occupies much of the attention given to projections of electric power use.

It is generally agreed that the forces which determine the use of electricity are numerous, and have complex inter-actions. In the making of projections concerning electric power use (demand and energy) in the United States, it is well to recognize the existence of an established order, in which the determinants may be different from those obtaining in nations having different characteristics. For this country, major

driving forces include, among others, the state of the national economy; established living standards and habits; population and its subdivisions of age, sex; income level, marital status; regional characteristics; and weather conditions.

The energy projections of Table 1 for some councils are the summation of projections made by the individual utility members. These projections may or may not have a common foundation with respect to inter-area population movements, employment levels, economic growth or other factors. While the projections made by each of the utilities in a council region may be validly based upon thorough economic and demographic analysis, each utility may have used different parameters, in a different model, and hence may have foreseen a different future. Therefore, the individual projections may not be truly additive, since the future foreseen by one forecast may be of a different nature from that foreseen by other forecasts. A common basis for the major factors, if used by all utilities, might have resulted in different forecasts. In order to avoid the problem of differing assumptions regarding future conditions, the New England Power Pool (NEPOOL) undertook the development of a regional forecasting model some time ago. An 18-month effort culminated in a comprehensive model^{1/} designed for long-term forecasting of electric power requirements in the six-state New England sub-area of NPCC. Following completion of this model in mid-1977, it was modified and up-dated, and served as a source for the

^{1/} Report on a Model for Long-Range Forecasting of Electric Energy and Demand. NEPOOL Load Forecasting Task Force and Battelle - Columbus Laboratories. June 30, 1977.

forecast energy data reported in the New England section of the April 1, 1979, Coordinated Planning Report of NPCC. A useful feature is the recording of the assumptions concerning the factors used in making the forecast. Documentation of this nature permits thoughtful evaluation of the results and assessment of the effects of changes in the basic premises. For instance, it is stated that the effects of certain factors have not been included in the forecast. These factors are^{1/}:

- time-of-day rates
- use of electric vehicles
- use of heat pumps
- solar-assisted space and water heating
- mandated conservation in industry and in the commercial sector

According to the NEPOOL Task Force Report ^{2/} the effects of the above-listed factors were excluded because of a lack of sufficient statistically valid data. However, when sufficient data are available, the effects can be factored into the model. Among the factors that were included are:

- weather correction
- population
- number of households
- employment (manufacturing and non-manufacturing separately)
- unemployment rate
- net of in-migration and out-migration
- personal income
- Federal efficiency goals for appliances

^{1/} Report on a Model for Long-Range Forecasting of Electric Energy and Demand. NEPOOL Load Forecasting Task Force and Battelle - Columbus Laboratories, June 30, 1977.

^{2/} Report of the NEPOOL Load Forecasting Task Force on the NEPOOL Model-Based Forecast of New England Electric Energy and Peak Demand 1979-1988, dated March 1, 1979.

availability of oil and gas for home
 heating
 changes in price level of electricity
 technological changes in New England
 industries
 system line losses (10.2 percent of peak
 load in winter, 6.9 percent of peak load
 in summer, 8.3 percent of net energy for
 load).

The other U. S. subdivision of NPCC, the New York Power Pool, adopted
 a different approach in its quest for a supportable forecast of energy and
 peak demand requirements.^{3/} Each of the Power Pool member utilities
 prepared a forecast for its service area, reviewing in great detail all
 the factors and parameters considered. Among these factors were:

population
 household formation patterns
 weather
 changes in the economy
 appliance saturation
 appliance efficiency standards
 increases in the price of electricity
 and other fuels
 effects of re-structured rates
 effects of load management

In addition to the individual utility forecasts, an independent study
 was made by National Economic Research Associates, using an econometric
 model to forecast state-wide peak load and energy requirements. Among the
 factors considered in this study were housing, income, real price of
 electricity and competitive fuels, gas appliance forecasts, appliance
 efficiency targets, industrial wage rate growth.

^{3/} Report of Member Systems of the New York Power Pool and the Empire
 State Electric Energy Research Corporation pursuant to Article III,
 Section 5-112 of the Energy Law of New York State. Volume I,
 pages 12-33. April 1, 1979.

The foregoing references to load forecasting are cited only to indicate the approaches to the topic taken in one Council. It is not intended herein to endorse the specific models referred to or the parameters utilized.

Table 13 is a review of the Council energy projections, made in 1976, 1977 and 1978, for the year 1978.

IV. PEAK DEMAND FORECASTS

The summer and winter peak demand forecasts reported by the Reliability Councils are summarized in Tables 2 and 9. In general, these forecasts are the arithmetic sums of the individual utility seasonal projections. For NPCC, the forecast is the sum of the NEPOOL and NYPP projections, which were obtained from regional models as discussed in Section III of this report. The NEPOOL and NYPP projections are estimates of coincident demand, but the total NPCC forecast, being the sum of the two individually computed subregional projections, is not coincident.

Since the peak demands of individual utilities within a large council area can be expected not to occur simultaneously, the regional peaks of Tables 2 and 9 should exceed the actual instantaneous regional peaks by some small amount. This diversity is in general expected to be small, on the order of 1 percent. The sum of the regional peaks shown on Tables 2 and 9 as the "7-Council Total" will, similarly, be somewhat higher than the coincident peak demand of the 7-Council Interconnection. This diversity gain cannot prudently be counted on as reserve capacity because of its unpredictable nature. Widespread occurrence of extreme weather conditions over a large part of any one Council area is not unknown, and such conditions may spread over adjoining portions of several councils, eliminating diversity of peak loads to a great extent.

Econometric analysis can help to develop estimates of the trend underlying increases in peak demand over a series of years. However, in any one year weather conditions may be such as to create peaks above or below the

projected trend. Unforeseen events, such as the 1973 oil embargo, can also operate to affect peak demands by means of economic impacts. Therefore, it should be recognized that the peak demands in Tables 2 and 9 are estimates based on current perceptions of the future. It is more likely that actual peaks (coincident or non-coincident) will differ from the projected values, than that they will correspond exactly.

Table 5 shows the reported actual peak summer demands (non-coincident) of the Reliability Councils for 1977. In that year, each council except WSCC and ERCOT experienced its summer peak in July, and the total U. S. peak also occurred in July. In the following year, as shown in Table 6, there was more diversity in time of summer peak load occurrence. The ECAR and MARCA peaks were in September; MAAC, MAIN, NPCC and SWPP peaked in August; SERC peaked in June; the WSCC and ERCOT peaks were in July. For some of the Councils, there were secondary summer peaks that were very little less than the major peak. As a result, although the U. S. total peak demand occurred in August, the total in July was only 0.7 percent lower, and for the entire period (June through September) the total of the monthly peaks was within 3 percent of the August peak. These tables illustrate the unreliable nature of dependence upon interregional diversity as a source of capacity. Table 7 shows the monthly peak load projections of the Councils for the June-September period of 1979, with July and August as the high load months. Actual data are not yet available to compare with the projections.

Table 8 is a comparison of projections made by the Reliability Councils in 1976, 1977, and 1978, for the summer peak load period of 1978. In all but two instances the projected demands exceeded the actual demands. MARCA's 1976 projection was .08 percent less than the actual 1978 peak for that Council, and the SWPP projection in 1978 was 0.63 percent less than its reported peak. Aside from these two instances, the projections ranged up to 12.99 percent higher than the actual value, and the magnitude of the error decreased as the time at which the projection was made approached the target period. ECAR's 1977 projection is an exception to the trend, as it was closer to the actual value than was the 1978 projection.

Peak demand forecasts play an important part in the planning of generating capacity. Strictly speaking, "the peak demand" occurs only for one hour of the year. However, experience has shown that as peak demand increases over a period of years, the demand during other hours of the year also increases, in general. Therefore, capacity planning must envisage not only supplying the single peak hour of the year but many other high-demand hours also, as well as increasing base load. Other factors, in addition to peak demand, influence the magnitude of capacity required for reliable service, but peak demand is regarded as a convenient (if limited) surrogate for some of them, at least as a first approximation.

For instance, the minimum annual demand is important, as it determines the magnitude of generating capacity that must always be in operation, to serve the "base load". This demand is not reported by the Reliability Councils, but its inclusion in future reports may well be worth consideration.

Figure 1 is a reproduction of a typical utility annual load duration curve, taken from the Environmental Report for the proposed Sundesert Nuclear Power Plant. Figure 2 shows an actual annual load duration curve, taken from the Environmental Report for the proposed Carroll County Nuclear Power Plant. A load duration curve shows the hourly loads during a specified period ranged in order of decreasing magnitude, not in chronological order. The exact shape of the annual curve would not be exactly the same for different utilities, and would differ from year to year even for any one utility, but the general shape is the same for many systems.

There is no exact demarcation of "peaking range" although the illustration of Figure 1 uses 200 hours as the "break point" of the curve. It is a matter of judgment as to whether 250 or 300 hours or even more should be regarded as the peaking range with respect to load.^{4/} In respect to the generating capacity used to meet various demand levels, the Powerplant and Industrial Fuel-Use Act of 1978 (Public Law 95-620) contains the following definitions (Section 103):

"(a)(18)(A) The term "peak load powerplant" means a powerplant the electrical generation of which in kilowatthours does not exceed, for any 12-calendar-month period, such powerplant's design capacity multiplied by 1,500 hours.

(B) The term "intermediate load powerplant" means a powerplant (other than a peakload powerplant) the electrical

^{4/} The Economic Regulatory Administration in its Interim Rule implementing the Powerplant and Industrial Fuel Use Act of 1978 solicited comments on how peak load demand should be defined for the purpose of the regulations. See Federal Register, Volume 4, No. 97, Thursday, May 17, 1979, page 28969. As of late September this matter has not been settled.

	<p>FIGURE 1.2.2 A TYPICAL ANNUAL LOAD DURATION CURVE ENVIRONMENTAL REPORT</p>
<p>Sundesert Nuclear Plant UNITS 1 & 2</p>	

AMENDMENT 4 – AUGUST 1977

FIGURE 1

*Total energy = 68,099,944 Mwh
 *Annual load factor = 56.7%

Note: This graph has been reproduced from the Carroll County Environmental Report. Items marked * have been added by ERA staff, from data in the Report.

REVISION 2 8/79

CARROLL COUNTY NUCLEAR GENERATING
 STATION - UNITS 1 & 2
 SITE SUITABILITY - ENVIRONMENTAL REPORT

FIGURE 1.1-10
 LOAD DURATION CURVE FOR 1978
 COMMONWEALTH EDISON COMPANY

FIGURE 2

generation of which in kilowatthours does not exceed, for any 12-calendar-month period, such powerplant's design capacity multiplied by 3,500 hours.

(C) The term "base load powerplant" means a powerplant the electrical generation of which in kilowatthours exceeds, for any 12-calendar-month period, such powerplant's design capacity multiplied by 3,500 hours.

The demand and energy forecasts are closely related, since the area under the load duration curve (the area between the curve, the load axis and the hours per year axis) represents the annual energy requirement. If it were possible to forecast the demand for each hour of the year, the total of the demands would be the annual energy requirement.

V. GENERATING CAPACITY FORECASTS

A. The need for generating capacity

Decisions concerning the installation of generating capacity are not made lightly, for several reasons. Among these are the large investments required, the long-term commitment of resources and personnel, the prospect of time-consuming adversary proceedings in regard to siting and environmental effects, and uncertainty as to the need for the capacity projected. Only the question of need for capacity is discussed here.

The need for capacity follows from the demand for electricity. In this discussion it is assumed that a pattern of future demand for electric power has been established, albeit with some degree of uncertainty attached to the magnitudes envisioned. On the basis of the load forecasts, it is then feasible to consider how much capacity is needed for reliable service.

Reliable service, from the customer's point of view, means that interruptions (failures of service) and perturbations (voltage and frequency fluctuations outside of an acceptable range) are few in number, occur only at widely-spaced intervals, are of short duration and do not occur at inconvenient times. Unreliable service may be due to events affecting transmission facilities, distribution facilities, generating units or other factors. Only generating capacity will be discussed here.

It is generally recognized that the generating capacity available to a power system must exceed the demand at all times, if reliable service is to be provided. Various methods are utilized

by system planners to determine how much capacity is needed to supply a specified load, and what allowance should be made for various contingencies that may modify the expected demand and the availability of capacity. The reserve margin is needed to provide for, among other things:

1. forced outages of generating units - failures of generating unit components that prevent a facility from delivering all or part of its normal output.
2. scheduled maintenance of generating units - routine work required to keep unit components in satisfactory, efficient operating condition, prevent failures and repair items that could be operated but might not be safe or reliable; also may include work necessitated by unforeseen complications resulting from previous repairs and modifications to equipment.
3. fuel supply problems -
 - a. unavailability of fuel due to embargo, strikes (fuel production or transportation), failure of oil or natural gas pipelines or other transportation systems.

- b. lowered fuel quality; the average heat content of coal delivered has decreased, for many utilities, resulting in decreased plant efficiency and greater in-plant capacity losses.
 - c. environmental restrictions, requiring fuel with lesser potential for undesirable emissions, may result in lower quality coal, reducing the output available from generating units; retrofitting of emission controls requires units to be shutdown for some time and reduces the output available from generating units.
- 4. transmission considerations -
 - a. inability to construct sufficient transmission facilities needed to efficiently move all generating unit output into the system, from all plants, reduces the capacity available at some plants and requires more to be available at other plants; the margin must therefore be larger than otherwise would be needed.
 - b. temporary transmission outages due to equipment failure, maintenance work or other causes, leading to difficulties in moving energy through the system, may require more capacity than would be the case if normal power flow patterns existed.

5. unusual weather conditions, summer or winter, may lead to greater demand than projected, reducing the margin. Unusually hot weather will also lead to a greater-than-usual decrease in the output obtainable from steam plants and gas turbine plants. Unusually wet weather increases corona losses on high voltage lines, and requires additional capacity to be available.
6. economic activity at levels greater than foreseen when load projections were made can be expected to require additional capacity to meet greater loads.
7. for systems with significant hydro capacity, drought conditions will reduce the capacity available and at the same time increase pumping demand for irrigation.
8. load regulation - capacity that must be instantaneously available to provide for instant-by-instant fluctuations in demand; the magnitude of such fluctuations may be as much as 2% to 3% greater than the average hourly demand.

The effects of inadequate capacity are evidenced by lower than normal voltage and frequency; abnormal fluctuations of voltage and frequency; unusual transfers of power between utilities; disconnection

of loads served under "interruptible" contracts; appeals by a utility to the public, to reduce the use of electric power; disconnection of supposedly "firm" loads by automatic equipment or under manual control by system personnel, causing "blackouts" of selected areas on a rotating basis; large-scale "blackouts."

The effect of an excessively high margin is to increase system cost and results in high revenue requirements. However, a system which determines that it has more reserve than it considers needed for reliability purposes may find it possible to sell the "excess" to systems which are in need of capacity. The purchase of capacity then allows the purchasing system to defer the construction of generating units. This sharing of "excess" reserves operates to reduce the total generation investment of two or more utilities.

B. How much reserve margin is needed?

Whatever method is used to determine the amount of capacity needed, the resulting capacity can be compared to the peak demand expected and the difference can be expressed as a percentage of that peak demand. It has been found, over a number of years and for many systems, that the planned reserve margin usually falls within the range of 15% to 25% of peak demand. Reserve margins in this range have been found to provide for reasonably adequate

generating capacity at costs that have not been considered excessive in the past. However, electric power supply systems have been undergoing continuous changes, and it does not necessarily follow that historical reserve margins are suitable for future systems. Among the factors that would tend to increase the needed reserve margin are: greater dependence on electric power by industrial and other consumers, resulting in greater need for reliable service; a trend toward larger units, which are more economical in terms of dollars per unit output, but which require greater reserve capacity as back-up; greater use of air-conditioning, which results in long-duration summer peaks and decreases the time available for maintenance work. Some countervailing factors are, among others: increased emphasis on making generating units more reliable, so that less capacity is required; load management techniques that reduce the magnitude of peak demands; conservation practices that reduce the use of energy and reduce peak demand; increased investment costs for generating capacity, resulting in the possibility that lower levels of reliability may be accepted.

The amount of reserve margin needed for a specific system is a function of that system's characteristics: the number, size and type of generating units; the geographical arrangement of the system's powerplants, service area and load centers; the load characteristics (magnitude of peak and base loads, variability of

daily and seasonal load, proportions of residential, industrial and other types of load); interconnections with other systems; and other factors. No fixed magnitude of reserve margin can be chosen that will be suitable for all systems at all times, because, in addition to the factors cited above, the desired reliability level and the presence of cost constraints exert significant pressures.

Reliability of service at the customer level is influenced by the transmission and distribution system, and by operating practices, as well as by the generating capacity reserve margin. Over-emphasis on capacity reserve could result in a costly system that would always have sufficient capacity but be unable to supply that capacity to its load centers and to its customers. On the other hand, reserves of too small a magnitude, although less costly in terms of capital investment, could result in greater cost to the utility and its customers over a period of time. When unable to serve its customers, a utility loses revenue and earns less return on its investment. When unable to obtain electric service, a customer may experience monetary losses and non-monetary losses. The monetary losses, to industrial and commercial customers, may result from spoilage of work in process, inability to manufacture salable products or proffer normal services, additional costs due to shut-down and start-up of production lines, for instance. Agricultural customers may suffer losses because of inability to operate irrigation systems, milking sheds, hatcheries or the like.

Residential consumers may suffer food spoilage because of inoperable freezers and refrigerators, inconvenience when space heaters and air conditioners fail to operate, hazards when lights fail. Normal life can be disrupted when gasoline pumps, traffic signals and sanitary pumping systems cannot operate. Situations such as these, if repeated over a period of time, result in an accumulation of costs that may well offset the reduction in investment cost gained by a reduction in reserve margin.

C. Reserve margins projected for 1979-1988

Tables 4 and 11 show the reserve generating capacity^{1/} projected by the Reliability Council reports, in megawatts and in percent of peak demand, for the summer and winter periods. These are composite reserves, obtained by aggregating the capacity and demand data reported to the Councils by their member utilities. As aggregates, the tabulated reserves do not mirror the reserves available to each utility within a Council area, since several factors would be operative: timing of peak demand, contractual obligations to systems outside the Council area, and transmission effectiveness within the Council area, among others.

The trend of the reserve margins is in general downward from 1978 to 1988. For the seven inter-connected councils the aggregate summer margin drops from 32.45 in 1978 (actual) to 23.30 in 1988. The winter margin decreases from 45.48 (1978-79) to 33.19 (1988-89).

^{1/} These margins exclude the effect of scheduled exchanges of capacity, which will increase the reserve margins in regions importing capacity and decrease them in regions exporting that capacity.

In the contiguous U.S. as a whole the summer margins decline from 33.59 to 23.97 in the same period and the winter margins also decline. However, the relatively high reserve margins for the 7-Council region and the total U.S. for the 1979-1988 period obscure some unfavorable realities of regional power supply situations. Margins are not uniformly high among the council region. In MARCA, the reserve margin in summer drops from 1982 on, reaching 4.72% in 1988. A margin of this magnitude is considered well below the level needed to maintain reliable service. In the Southwest Power Pool, the summer margin drops from 19.24% in 1986 to 14.65% in 1988; the 1988 margin is on the edge of the usual range. The MAIN margin, in 1986, 1987 and 1988, is barely within the lower limit of the usual range.

There are two factors which could operate to reduce the MAIN and SWPP reserves below the barely adequate level in the late 1980's: moderate increases in peak demand growth and delays in completion of currently scheduled generating units. Either of these factors in itself could reduce the margins, not only in the regions referred to but in any region. Both factors together would have an effect that is potentially very troublesome. It is certainly true that load growth may be less than that which is now forecast. In that case, the reserve margins would improve if current construction schedules are maintained. If lower load growth does occur, the result could be more capacity than needed

for reliable service and costs temporarily higher than would appear necessary in the late 1980's. However, reduced load growth can readily be accommodated by postponements of generating unit construction. But increased load growth could not be so readily accommodated, because accelerated construction of large power plants is not easily accomplished. Experience in the last few years indicates that many obstacles have been encountered in the construction of generating capacity and in the development of fuel resources for electric power generation.

A weighing of the consequences attendant upon inadequate electric power supply, versus those resulting from higher reserve margins, indicates that prudent planning would lean towards more reserves rather than less. It appears desirable to plan, for the long term, on the availability of reserves in the high end of the (previously acceptable) range rather than risk the unreliability that could follow from planning for the low end of the range.

D. The Effect of Three Mile Island No. 2 on Generating Capacity and Reserve Margins

The generating capacity and reserve margin projections of Tables 3, 4, 10 and 11 are based on data compiled by the Reliability Councils in late 1978 and early 1979 prior to the forced outage of the Three Mile Island No. 2 Nuclear Unit. Data compiled prior to that incident includes the capacity of TMI 2. Reserve margins, including that unit, as shown in Tables 4 and 11, are the planned reserve margins, intended to allow for the forced outages and other incidents normally encountered in power system planning and operation. The events leading to the forced outage of TMI 2 began on the morning of March 28, 1979,^{1/} therefore there is no discussion of the incident in the Reliability Council reports received April 1, 1979 by the Department of Energy. It is appropriate to note that the forced outage of TMI 2 is an instance of the type of occurrence for which utilities must provide in their long-range planning of reserve margins.

The nature of the generating unit involved and the severity of the incident as it affected the unit make it probable that the forced outage will be of much longer duration than the forced outages of generating units normally experienced. For that reason

^{1/} Investigation Into The March 28, 1979 Three Mile Island Accident By Office of Inspection And Enforcement.
Investigative Report No. 50-320/79-10
U.S. Nuclear Regulatory Commission, Washington, D.C., August 1979

it appears prudent to examine the effect of removing the capacity of TMI 2 from the installed capacity and reserves of the utility directly affected (General Public Utilities Corp.) and the Council Region in which the utility is located (MAAC). This analysis is made only for the purpose of assessing such effect on reliability as may be deduced from consideration of installed reserve margins.

In order to consider the worst possible effect of the TMI 2 incident on reserve margins, it will be assumed here that the unit will not be available for normal commercial operation during the time frame of the 1979-1988 reporting period. This assumption is not based on a judgment as to the actual duration of the forced outage but is made only for the purposes of convenient analysis. A return of the unit to service prior to the winter of 1988-89 would serve to ameliorate the effects discussed below.

Three Mile Island Nuclear Unit No. 2, according to the MAAC Report of April 1, 1979, has a summer net capability of 880 MW and a net winter capability of 906 MW. These magnitudes are subtracted from the summer and winter reserve capacities projected for the GPU system, to obtain the effect of the incident. The reduced reserves of GPU are shown in the table below. It appears that the reduced reserves in the summer peak periods of 1980 through 1983 and in the winter peak periods of 1981-82 and 1982-83, are well below the minimum needed to assure reasonably reliable service. The reserves in the summers of 1984, 1985 and 1987, and in the winters of 1980-81 and 1987-88, also appear too low.

Effect of TMI 2 on GPU Reserves

<u>Year</u>	<u>Reserves With TMI 2^{1/}</u>		<u>Reserves Without TMI 2</u>	
	<u>MW</u>	<u>%</u>	<u>MW</u>	<u>%</u>
<u>Summer Peak Periods</u>				
1980	1,550	25.14	670	10.87
1981	1,306	20.37	426	6.65
1982	1,276	18.99	396	5.89
1983	1,118	16.14	238	3.44
1984	1,843	25.80	963	13.48
1985	1,693	22.99	813	11.04
1986	2,090	27.53	1,210	15.94
1987	1,825	23.32	945	12.07
1988	2,207	27.35	1,327	16.44
<u>Winter Peak Periods^{1/}</u>				
1979-80	1,994	31.68	1,088	17.28
1980-81	1,809	27.92	903	13.94
1981-82	1,515	22.36	609	8.99
1982-83	1,585	22.50	679	9.64
1983-84	2,429	33.28	1,523	20.87
1984-85	2,166	28.64	1,260	16.66
1985-86	2,663	33.99	1,757	22.43
1986-87	2,381	29.34	1,475	18.17
1987-88	2,051	24.39	1,145	13.62
1988-89	2,373	27.24	1,467	16.84

^{1/} Reserves are based on GPU existing capacity as of December 31, 1978 and projected changes in capacity through 1988, as reported in the April 1, 1979 MAAC Report to DOE; on GPU peak demands as reported in the GPU Form 12 Report (Schedule 19) to FERC (as of December 31, 1978) for 1979 through 1982; and on assumed annual load growth of 3.1% for summer peak demand and 3.6% for winter peak demand after 1982.

The effects on the MAAC Region, within which the GPU system is located, are shown the table below. At no time in the period 1979-1988 does the projected summer reserve capacity of MAAC, without TMI 2, fall below 29.00% of the projected peak demand. The projected winter peak period reserve capacity during the period 1979-80 through 1988-89, without TMI 2, has a minimum value of 46.80% in the winter of 1988-89 and for the remainder of the period is greater than 49%. These reserve margins, when compared to the usually planned range of 15% to 25%, indicate no serious deterioration of reliability for MAAC as a whole as resulting from the TMI 2 incident, provided no transmission problems develop.

Effect of Removing TMI 2 Capacity
on MAAC Reserves
1979-1988

<u>Year</u>	<u>Reserves With TMI 2^{1/}</u>		<u>Reserves Without TMI 2</u>	
	<u>MW</u>	<u>%</u>	<u>MW</u>	<u>%</u>
	<u>Summer Peak Periods</u>			
1979	11,896	35.57	11,016	32.94
1980	11,919	34.61	11,039	32.06
1981	12,219	34.34	11,339	31.86
1982	13,019	35.30	12,139	32.92
1983	11,921	31.32	11,041	29.00
1984	12,452	31.77	11,572	29.52
1985	13,296	32.89	12,416	30.71
1986	14,061	33.83	13,181	31.71
1987	14,671	34.31	13,791	32.26
1988	14,046	31.92	13,166	29.92
	<u>Winter Peak Periods^{1/}</u>			
1979-80	19,355	65.20	18,449	62.15
1980-81	18,617	60.49	17,711	57.55
1981-82	18,407	57.46	17,501	54.63
1982-83	19,318	58.04	18,412	55.31
1983-84	18,158	52.53	17,252	49.91
1984-85	19,715	55.06	18,809	52.53
1985-86	19,770	53.38	18,864	50.93
1986-87	20,143	52.58	19,237	50.22
1987-88	20,682	52.26	19,776	49.97
1988-89	20,027	49.02	19,121	46.80

In summary, the lack of TMI 2 capacity will force GPU to obtain capacity from other systems from time to time during the period 1979-1980, in order to provide reliable service. That capacity is available within MAAC and within the 7-Council Interconnection, to the extent that the transmission facilities will permit its transfer to the GPU system.

VI. PURCHASES AND SALES OF CAPACITY

Electric utilities arrange for scheduled purchases and sales of capacity when such transactions appear to be technically and economically feasible. A transaction may be planned when one utility foresees a temporary excess of capacity and another utility wishes to defer construction of a generating unit. A transaction may be arranged when a utility or group of utilities in one area and a utility or group of utilities in another area discover a consistent pattern of load diversity between them. If the diversity is of large enough magnitude, and it is believed that the diversity will endure for a reasonable length of time, interchange arrangements can be made. Two or more utilities may agree to construct a single large unit (or a plant with several large units) and share the output, instead of each constructing a small unit. The advantages of scale are thereby obtained, with lower investment cost per unit of capacity for each participant. The large unit (or plant) can be operated by one of the parties on behalf of all. Contractual arrangements of various types can be developed for such a situation, one being for each participant to treat the power flow as a capacity purchase. In all instances, the transactions are arrangements between utilities, not between Regional Councils, although the Council organizational structure facilitates such arrangements.

The inter-utility transactions in capacity, when effected between members of one Council, will not in general change the regional reserve margin (although regional capacity will be more effectively used). When the utilities participating in a capacity exchange are in two different Council regions, the regional reserve margins will be modified if the transactions are scheduled to occur at the time of peak load in either or both regions. Tables 14 and 15 summarize data on inter-regional capacity movements scheduled for the winter and summer peak

periods from 1979 through 1988-89. In the tables, total scheduled imports and exports are shown. Some Councils have scheduled interregional capacity exchanges to a much greater extent than others. ECAR, MAIN, SERC and SWPP show larger scheduled exports during the summer peak period than do the other councils. Exports during the winter peak period are larger for ECAR, MAIN, MARCA and SWPP. MAAC and NPCC have no inter-regional exports scheduled for the winter or summer peak periods, altho both regions have scheduled imports for those periods.

Long-term scheduling of capacity transactions among utilities requires joint consideration by at least two parties, with detailed attention being given to costs, capacity requirements and construction, projected loads, transmission availability and system operating considerations, among other things.

VII. TRANSMISSION

The table below compares current transmission construction projections, for the period 1979-88, with those made a year earlier for 1978-87.

Transmission Construction Projected
In the April 1 Council Reports

<u>Voltage Level</u> KV ^{1/}	<u>Projected 4/1/79 For 1979-88</u>		<u>Projected 4/1/78 For 1978-87</u>	
	<u>Miles</u>	<u>%</u>	<u>Miles</u>	<u>%</u>
115 to 161	2,978	4.91	2,322	4.12
230	15,981	26.35	16,523	29.30
287	1	0.00	1	0.00
345	22,433	36.99	20,630	36.58
500	14,555	24.00	11,845	21.01
765	2,657	4.38	2,551	4.52
400 ^{2/}	-0-	-0-	423	0.75
1,000 ^{2/}	<u>2,042</u>	<u>3.37</u>	<u>2,096</u>	<u>3.72</u>
Total	60,647	100.00	56,391	100.00

^{1/} All voltages are AC unless otherwise stated

^{2/} D.C.

The highest AC transmission voltage projected for the next decade is 765 KV. Studies are in progress on the use of higher voltage levels, but no higher AC voltage is projected by any system for completion by 1988.

Although current projections of growth in demand, energy and generating capacity are now less than they were a year earlier, estimated transmission mileage construction has increased by 7.5% over the previous year's projection. Among the results to be expected from the combination of these projections would be somewhat lower transmission losses, greater network reliability and more flexibility in arranging transfers of power among utilities.

VIII - Tables 1 Through 17

Table 1
PROJECTED GROWTH OF COUNCIL REGION NET ANNUAL ENERGY REQUIREMENTS
1978-1988
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY -- APRIL 1, 1979
CONTIGUOUS UNITED STATES

Council	1978 Actual	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	Average Annual Percent Increase	
												1978-88	1979-88
		Gigawatthours (= Thousands of Megawatthours)*										1/ 4.5	2/ 4.4
ECAR ^{3/}	369,108	390,100	408,400	427,800	443,500	461,200	481,900	503,100	526,100	548,300	573,200		
MAAC	169,766	175,386	182,155	188,816	196,091	203,286	210,608	217,732	224,991	232,248	239,579	3.5	3.5
MAIN	168,808	177,580	186,933	195,389	204,312	213,266	222,430	232,799	243,555	255,030	267,604	4.7	4.7
MARCA ^{4/}	92,477	96,774	102,741	108,060	114,206	120,312	127,347	134,931	141,306	149,831	157,303	5.5	5.5
NPCC	198,918	209,952	215,386	222,343	230,225	238,243	247,289	256,019	264,408	272,666	280,706	3.5	3.3
SERC	452,750	480,063	510,626	545,674	575,688	606,048	640,457	673,371	702,605	732,415	764,831	4.8	4.6
SWPP	191,550	201,889	217,765	229,545	244,391	259,641	276,037	293,168	311,214	329,657	349,140	6.2	6.3
7-Council Sub-total	1643377	1731744	1824006	1917627	2008413	2101996	2206068	2311170	2414179	2520147	2632363	-	-
Annual Increase													
Gwh		88,367	92,262	93,621	90,786	93,583	104,072	105,102	103,009	105,968	112,216	-	-
%		5.38	5.33	5.13	4.73	4.66	4.95	4.76	4.46	4.39	4.45	4.8	4.8
WSCC ^{4/}	410,135	438,638	458,168	484,434	509,402	530,486	554,693	578,040	603,229	629,088	656,924	4.8	4.6
ERCOT	147,371	151,125	159,872	169,353	178,221	187,154	196,010	206,175	215,459	225,714	236,886	4.9	5.1
U.S. Total	2200883	2321507	2442046	2571414	2696036	2819636	2956771	3095385	3232867	3374949	3526173	-	-
Annual Increase													
Gwh		120,624	120,539	129,368	124,622	123,600	137,135	138,618	137,478	142,082	151,224	-	-
%		5.48	5.19	5.30	4.85	4.58	4.86	4.69	4.44	4.39	4.48	4.8	4.8

*As reported in Item 1 of the Council reports. Net energy is the electric energy required from all power sources during the reporting period to satisfy the energy requirements of customers and supply losses in the transmission and distribution system. It includes the net energy from installed power sources and energy supplied by other sources such as interconnected utility systems and industrial sources. It does not include the energy required for pumping of pumped storage plants.

1/ Average of 10 annual increases from 1978 to 1988.

2/ Average of 9 annual increases from 1979 to 1988. The growth rates reported in the July 1978 DOE Report on Electric Power Supply and Demand 1978-1987 (DOE/ERA-0018) were computed on this basis.

3/ Total of Bulk Power and Liaison System Members

4/ U.S. portion of Council only.

Table 2
PROJECTED GROWTH OF COUNCIL REGION SUMMER PEAK DEMANDS
1978-1988
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY -- APRIL 1, 1979
CONTIGUOUS UNITED STATES

<u>Council</u>	<u>1978</u> <u>Actual</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>Average Annual</u> <u>Percent Increase</u>	
				<u>- Megawatts * -</u>								<u>1978-88</u>	<u>1979-88</u>
	<u>1/</u>											<u>2/</u>	<u>3/</u>
ECAR	62,454	65,873	68,745	71,853	74,681	77,989	81,355	85,069	88,697	92,400	96,354	4.4	4.3
MAAC	31,812	33,446	34,436	35,586	36,876	38,066	39,196	40,426	41,566	42,756	44,006	3.3	3.1
MAIN	33,222	36,271	38,040	39,698	41,388	43,150	44,960	46,900	48,887	50,972	53,091	4.8	4.3
MARCA ^{4/}	19,012	19,470	20,824	21,928	23,140	24,361	25,657	27,066	28,392	29,736	31,147	5.6	5.4
NPCC ^{4/}	34,876	36,999	37,918	39,064	40,379	41,723	43,188	44,684	46,052	47,415	48,663	3.4	3.1
SERC	80,475	87,209	92,832	99,079	105,028	109,845	116,438	122,020	127,695	133,605	139,730	5.7	5.4
SWPP	39,191	41,094	43,705	46,492	49,468	52,477	55,679	59,081	62,559	66,200	69,987	6.0	6.1
7-Council Subtotal	300,042	320,362	336,500	353,700	370,960	387,611	406,473	425,246	443,848	463,084	482,978	-	-
Annual Increase													
MW		20,320	16,138	17,200	17,260	16,651	18,862	18,773	18,602	19,236	19,894	-	-
%		6.77	5.04	5.11	4.88	4.49	4.87	4.62	4.37	4.33	4.30	4.9	4.7
WSCC ^{4/}	63,719	75,607	79,286	83,055	87,247	90,398	94,336	98,364	102,567	106,893	111,303	5.0	4.4
ERCOT	23,645	30,443	32,096	33,819	35,531	37,306	39,276	41,281	43,184	45,313	47,559	5.2	5.1
U.S. Total	397,406	426,412	447,882	470,574	493,738	515,315	540,085	564,891	589,599	615,290	641,840	-	-
Annual Increase													
MW		29,006	21,470	22,692	23,164	21,577	24,770	24,806	24,708	25,691	26,550	-	-
%		7.30	5.04	5.07	4.92	4.37	4.81	4.59	4.37	4.36	4.32	4.9	4.7

*As reported in Item 1 of the Council reports. The peak demands of the Councils are not necessarily coincident in time. The actual 7-Council subtotals and the U.S. totals will be less than the totals shown here because the Council peaks occur at different times. The totals are shown only to indicate the approximate level of 7-Council and national peak power use. The demands include interruptible loads and exclude inter-regional purchases and sales.

Total U.S. increase in peak demand 1978 to 1988 = 244,434 MW

1/ Summer peak demand regardless of month in which it occurred.

2/ Average of the 10 annual increases from 1978 to 1988.

3/ Average of the 9 annual increases from 1979 to 1988. The growth rates reported in the July 1978 DOE Report on Electric Power Supply and Demand 1978-1987 (DOE/ERA-0018) were computed on this basis.

4/ U.S. portion of Council only.

Table 3
 PROJECTED GROWTH OF COUNCIL REGION SUMMER GENERATING CAPACITY
 1978-1988
 AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
 TO THE DEPARTMENT OF ENERGY -- April 1, 1979
 Contiguous United States

Council	1978 1/	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	Average Annual Percent Increase	
Generating Capacity In Megawatts at Time of Summer Peak Demand												1978-88	1979-88
ECAR	85,595	87,330	89,693	97,256	97,836	103,660	108,454	114,867	119,392	121,874	126,620	3.9	4.2
MAAC	44,433	45,342	46,355	47,805	49,895	49,987	51,648	53,722	55,627	57,427	58,052	2.9	2.8
MAIN 3/	41,773	43,219	45,036	46,063	50,548	55,276	55,894	56,118	56,533	59,620	61,985	3.8	4.1
MARCA 3/	21,697	24,527	25,311	27,707	28,122	28,680	29,867	30,320	32,236	32,684	32,618	4.1	3.3
NPCC 3/	50,734	50,436	51,388	52,191	52,477	53,768	53,536	56,369	58,523	59,378	61,953	2.3	2.3
SERC	106,708	111,323	118,631	124,708	132,880	138,990	145,601	157,240	161,857	168,181	174,054	5.0	5.1
SWPP	46,457	47,802	53,020	57,260	60,289	63,196	66,929	70,394	74,598	77,386	80,237	5.6	5.9
7-Council Subtotal	397,397	409,979	429,434	452,990	472,047	493,557	511,929	539,030	558,766	576,550	595,519	-	-
Annual Increase													
MW		12,582	19,455	23,556	19,057	21,510	18,372	27,101	19,736	17,784	18,969	-	-
%		3.17	4.75	5.49	4.21	4.56	3.72	5.29	3.66	3.18	3.29	4.1	4.2
WSCC 3/	94,521	95,143	101,915	104,877	110,164	115,894	121,555	127,177	132,398	138,444	144,158	4.6	4.7
ERCOT	38,984	40,944	42,419	43,907	45,402	48,245	49,338	50,310	52,720	54,079	56,025	3.8	3.6
U.S. Total	530,902	546,066	573,768	601,774	627,613	657,696	682,822	717,517	743,884	769,073	795,702	-	-
Annual Increase													
MW		15,164	27,702	28,006	25,839	30,083	25,126	34,695	26,367	25,189	26,629		
%		2.86	5.07	4.88	4.29	4.79	3.82	5.08	3.57	3.39	3.46	4.1	4.3

Total increase in U.S. summer capacity 1978 to 1988 = 264,800 MW.

1/ Actual summer 1978 installed capability as reported by National Electric Reliability Council.

2/ Net Dependable Capability as projected on Line 01 of Item 3A of the April 1, 1979 Reliability Council Reports to DOE.
 Excludes purchases and sales of capacity.

3/ U.S. portion of Council only.

Table 4
PROJECTED INSTALLED RESERVE GENERATING CAPACITY OF COUNCIL REGIONS
AT TIME OF PEAK SUMMER DEMAND 1978-1988
FROM DATA REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
CONTIGUOUS UNITED STATES

Council	1978 Actual	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
<u>Reserve Capacity In Megawatts^{1/}</u>											
ECAR	23,141	21,457	20,948	25,403	23,155	25,671	27,099	29,798	30,695	29,474	30,266
MAAC	12,621	11,896	11,919	12,219	13,019	11,921	12,452	13,296	14,061	14,671	14,046
MAIN	8,551	6,948	6,996	6,365	9,160	12,126	10,934	9,218	7,646	8,648	8,894
MARCA ^{2/}	3,685	5,057	4,487	5,779	4,982	4,319	4,210	3,254	3,844	2,948	1,471
NPCC ^{2/}	15,858	13,437	13,470	13,127	12,098	12,045	10,348	11,685	12,471	11,963	13,290
SERC	26,233	24,114	25,799	25,629	27,852	29,145	29,163	35,220	34,162	34,576	34,324
SWPP	7,266	6,708	9,315	10,768	10,821	10,719	11,250	11,313	12,039	11,186	10,250
7-Council Sub-total	97,355	89,617	92,934	99,290	101,087	105,946	105,456	113,784	114,918	113,466	112,541
WSCC ^{2/}	25,802	19,536	22,629	21,822	22,917	25,496	27,219	28,813	29,831	31,551	32,855
ERCOT	10,339	10,501	10,323	10,088	9,871	10,939	10,062	10,029	9,536	8,766	8,466
U.S. Total	133,496	119,654	125,886	131,200	133,875	142,381	142,737	152,626	154,285	153,783	153,862
<u>Reserve Capacity As A Percentage Of Summer Peak Demand</u>											
ECAR	37.05	32.57	30.47	35.35	31.01	32.92	33.31	35.03	34.61	31.90	31.41
MAAC	39.67	35.57	34.61	34.34	35.30	31.32	31.77	32.89	33.83	34.31	31.92
MAIN	25.74	19.16	18.39	16.03	22.13	28.10	24.32	19.65	15.64	16.97	16.75
MARCA ^{2/}	20.46	25.97	21.55	26.35	21.53	17.73	16.41	12.02	13.54	9.91	4.72
NPCC ^{2/}	45.47	36.32	35.52	33.60	29.96	28.87	23.96	26.15	27.08	25.23	27.31
SERC	32.60	27.65	27.79	25.87	26.52	26.53	25.05	28.86	26.75	25.88	24.56
SWPP	18.54	16.32	21.31	23.16	21.87	20.43	20.21	19.15	19.24	16.90	14.65
Aver. 7-Councils	32.45	27.97	27.62	28.07	27.25	27.33	25.94	26.76	25.89	24.50	23.30
WSCC ^{2/}	37.55	25.84	28.54	26.27	26.27	28.20	28.85	29.29	29.08	29.52	29.52
ERCOT	36.09	34.49	32.16	29.83	27.78	29.32	25.62	24.29	22.08	19.35	17.80
Aver. U.S.	33.59	28.06	28.11	27.88	27.11	27.63	26.43	27.02	26.17	24.99	23.97

Total increase in summer reserve margin 1978-1988 = 20,366 MW.

^{1/} Reserve capacity = Generating Capacity of Table 3 less Peak Demand of Table 2.

^{2/} U.S. Portion Only.

Table 5
1977 Actual Summer Electric Demands
Contiguous United States
As Reported by the Reliability Councils^{1/}

<u>Council</u>	<u>Monthly Peak Demands - Megawatts</u>			
	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>
ECAR	56,061	62,306	58,506	58,980
MAAC	26,843	32,306	29,894	30,376
MAIN	28,913	33,404	29,468	27,449
MARCA	15,801	17,549	14,078	13,038
NPCC	30,340	35,448	33,693	32,821
SERC	75,821	79,332	77,377	74,704
SWPP	33,439	36,514	35,644	33,037
Sub-total	267,218	296,859	278,660	270,405
WSCC	61,904	64,676	64,926	64,036
ERCOT	24,656	26,407	26,819	26,230
U.S. Total	353,778	387,942	370,405	360,671
% of Peak	91.2	100.0	95.5	93.0

^{1/} April 1, 1978 Reports to Dept. of Energy under
FPC Docket R-362. Item 1

Table 6
1978 Actual Summer Electric Demands
Contiguous United States
As Reported by the Reliability Councils^{1/}

<u>Council</u>	<u>Monthly Peak Demands - Megawatts</u>			
	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>
ECAR	60,277	61,601	60,390	61,927
MAAC	29,529	30,409	31,812	29,528
MAIN	31,765	32,443	33,000	32,602
MARCA	16,141	16,981	17,580	17,596
NPCC	32,113	33,858	34,876	30,962
SERC	80,475	78,812	79,892	78,882
SWPP	36,570	38,339	38,378	36,249
Sub-total	<u>286,870</u>	<u>292,443</u>	<u>295,928</u>	<u>287,746</u>
WSCC	66,797	68,719	68,360	67,525
ERCOT	<u>27,294</u>	<u>28,645</u>	<u>28,164</u>	<u>26,763</u>
U.S. Total	380,961	389,807	392,452	382,034
% of Peak	97.1	99.3	100.0	97.3

^{1/} April 1, 1979 Reports to Dept. of Energy under FPC Docket R-362. Item 1

Table 7
1979 Projected Summer Electric Demands
Contiguous United States
As Reported by the Reliability Councils ^{1/}

<u>Council</u>	<u>Monthly Peak Demands - Megawatts</u>			
	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>
ECAR	62,448	65,118	65,261	60,961
MAAC	31,156	32,896	33,446	30,166
MAIN	33,931	36,067	35,357	32,221
MARCA	16,971	19,348	18,989	16,433
NPCC	34,910	36,020	36,999	33,560
SERC	82,569	85,293	86,828	82,098
SWPP	38,492	40,819	40,975	38,220
Sub-total	300,477	315,561	317,855	293,659
WSCC	72,706	75,297	75,607	72,442
ERCOT	<u>27,935</u>	<u>29,799</u>	<u>30,431</u>	<u>28,763</u>
U.S. Total	401,118	420,657	423,893	394,864
% of Peak	94.6	99.2	100.0	93.2

^{1/} April 1, 1979 Reports to Dept. of Energy under
FPC Docket R-362. Item 1

Table 8
Accuracy of Peak Load Projections for Summer 1978
Made in 1976, 1977 and 1978
By Regional Electric Reliability Councils

Council	Summer Peak Demand			Actual 1978	(Projected) - (Actual)			Difference as Percent		
	Projected for 1978				= Difference			of Projected		
	in	in	in		1976	1977	1978	1976	1977	1978
	1976	1977	1978		- Megawatts -			- % -		
ECAR	66,738	63,461	66,055	62,454	4,284	1,007	3,601	6.42	1.59	5.45
MAAC	35,660	34,200	32,713	31,812	3,848	2,388	901	10.79	6.98	2.75
MAIN	37,297	35,716	35,003	33,222	4,075	2,494	1,781	10.93	6.98	5.36
MARCA	17,998	18,945	18,651	18,012	(14)	933	639	(0.08)	4.92	3.43
NPCC	37,599	37,078	35,710	34,876	2,723	2,202	834	7.24	5.94	2.34
SERC	92,485	88,481	84,400	80,475	12,010	8,006	3,925	12.99	9.05	4.65
SWPP	41,250	39,895	38,946	39,191	2,059	704	(245)	4.99	1.76	(0.63)
Sub-total	329,027	317,776	311,478	300,042	28,985	17,734	11,436	8.81	5.58	3.67
WSCC	76,397	74,867	71,937	68,719	7,678	6,148	3,218	10.05	8.21	4.47
ERCOT	30,161	29,305	28,949	28,645	1,516	660	304	5.03	2.25	1.06
U.S. Total	435,585	421,948	412,364	397,406	38,179	24,542	14,958	8.76	5.82	3.76

This table compares projections of 1978 Summer Peak Demand, made in the Regional Electric Reliability Council Reports filed April 1 in the years 1976, 1977 and 1978, with the actual 1978 Summer Peak Demand reported in the April 1, 1979 Council Reports.

Table 9
PROJECTED GROWTH OF COUNCIL REGION WINTER PEAK DEMANDS
1978-79 TO 1988-89
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1979
CONTIGUOUS UNITED STATES

Council	1978-79 Actual	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	Average Annual Percent Increase	
												From 78-79	From 79-80
	1/ 63,450	66,792	70,198	73,616	76,907	80,297	84,337	88,215	92,286	96,388	100,915	2/ 4.8	3/ 4.7
ECAR	28,655	29,686	30,776	32,036	33,286	34,566	35,806	37,036	38,306	39,576	40,856	3.6	3.6
MAAC	28,099	29,780	31,289	32,786	34,398	36,015	37,796	39,593	41,513	43,553	45,677	5.0	4.9
MAIN	16,631	17,821	18,926	20,104	21,227	22,450	23,776	25,072	26,426	27,819	29,237	5.8	5.7
MARCA ^{4/}	34,267	36,525	37,596	38,946	40,342	41,865	43,368	44,852	46,227	47,599	48,835	3.6	3.3
NPCC ^{4/}	81,527	89,636	95,725	101,878	107,209	113,258	119,752	125,518	131,337	137,471	143,792	5.8	5.4
SERC	28,350	29,349	31,292	33,290	35,461	37,867	39,978	42,407	44,918	47,563	50,330	5.9	6.2
SWPP	7-Council Sub-total	280,979	299,589	315,802	332,656	348,830	366,318	384,813	402,693	421,013	439,969	-	-
Annual Increase													
MW		18,610	16,213	16,854	16,174	17,488	18,495	17,880	18,320	18,956	19,673	-	-
%		6.62	5.41	5.34	4.86	5.01	5.05	4.65	4.55	4.50	4.47	5.0	4.9
WSCC ^{4/}	70,069	73,178	77,080	80,810	84,279	87,764	91,488	95,329	99,485	103,618	107,538	4.4	4.4
ERCOT	21,505	22,029	23,309	24,486	25,771	27,209	28,657	29,938	31,400	33,056	34,715	4.9	5.2
U.S. Total	372,553	394,796	416,191	437,952	458,880	481,291	504,958	527,960	551,898	576,643	601,895		-
Annual Increase													
MW		22,243	21,395	21,761	20,928	22,411	23,667	23,002	23,938	24,745	25,252	-	-
%		5.97	5.42	5.23	4.78	4.88	4.92	4.56	4.53	4.48	4.38	4.9	4.8

*As reported in Item 1 of the Council reports. The peak demands of the Councils are not necessarily coincident in time. The actual 7-Council subtotals and the U.S. totals will be less than the totals shown here because the Council peaks occur at different times. The totals are shown only to indicate the approximate level of 7-Council and national peak power use. The demands include interruptible loads and exclude inter-regional purchases and sales.

1/ Winter period (December 1978, January 1979, February 1979) peak demand, regardless of month in which it occurred, as reported by NERC, plus interruptible loads reported in the April 1, 1978 Council Reports. The NERC data reported excludes interruptible loads.

2/ Average of 10 annual increases from 1978-79 to 1988-89.

3/ Average of 9 annual increases from 1979-80 to 1988-89. The growth rates reported in the July 1978 DOE Report on Electric Power Supply and Demand 1978-1987 (DOE/ERA-0018) were computed on this basis.

4/ U.S. portion of Council only.

- Table 10
PROJECTED GROWTH OF COUNCIL REGION WINTER GENERATING CAPACITY
1978-1988
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
CONTIGUOUS UNITED STATES

Council	1978-79 Actual	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	Average Annual Percent Increase	
	<u>1/</u>	<u>Generating Capacity In Megawatts at Time of Winter Peak Demand^{2/}</u>										1978-79	1979-80
ECAR	86,614	90,328	96,423	99,250	102,413	107,039	114,196	118,542	123,532	126,226	131,727	4.3	4.3
MAAC	48,023	49,041	49,393	50,443	52,604	52,724	55,521	56,806	58,449	60,258	60,883	2.4	2.4
MAIN	42,984	45,211	47,076	49,672	55,532	56,787	57,037	57,235	57,657	61,284	63,883	4.1	4.0
MARCA ^{3/}	22,763	25,770	27,212	28,513	29,204	29,884	30,499	31,118	33,506	33,475	34,294	4.2	3.2
NPCC ^{3/}	52,691	52,255	53,873	54,234	54,428	55,572	57,371	59,559	60,549	63,002	63,975	2.0	2.3
SERC	109,038	115,902	121,883	129,798	135,199	142,844	151,335	161,949	164,002	170,943	176,153	4.9	4.8
SWPP	46,664	48,822	53,462	57,162	60,743	63,097	67,948	71,271	75,156	77,808	81,301	5.7	5.8
7-Council Subtotal	408,777	427,329	449,322	469,072	490,123	507,947	533,907	556,480	572,851	592,996	612,216	-	-
Annual Increase													
MW		18,552	21,993	19,750	21,051	17,824	25,960	22,573	16,371	20,145	19,220		
%		4.54	5.15	4.40	4.49	3.64	5.11	4.23	2.94	3.52	3.24	4.1	4.1
WSCC ^{3/}	93,629	98,810	103,197	108,116	112,289	117,947	123,368	128,594	134,712	139,536	146,223	4.6	4.5
ERCOT	39,644	41,435	43,907	43,752	47,070	49,338	49,057	51,657	53,355	54,504	57,110	3.7	3.7
U.S. Total	542,050	567,574	596,426	620,940	649,482	675,232	706,332	736,731	760,918	787,036	815,549	-	-
Annual Increase													
MW		25,524	28,852	24,514	28,542	25,750	31,100	30,339	24,187	26,118	28,513		
%		4.71	5.08	4.11	4.60	3.96	4.61	4.30	3.28	3.43	3.62	4.2	4.1

1/ Installed capability as reported by NERC.

2/ Net dependable capability as reported in Line 01 of Item 3A, in the April 1, 1979 Reliability Council Reports.
 Excludes purchases and sales (imports and exports) of capacity.

3/ U.S. portion only.

Table 11
PROJECTED INSTALLED RESERVE GENERATING CAPACITY OF COUNCIL REGIONS
AT TIME OF PEAK WINTER DEMAND 1978-1988
FROM DATA REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
CONTIGUOUS UNITED STATES

	1978-79 Actual	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89
<u>Reserve Capacity In Megawatts^{1/}</u>											
ECAR	23,154	23,536	26,225	25,634	25,506	26,742	29,859	30,327	31,246	29,838	30,812
MAAC	19,368	19,355	18,617	18,407	19,318	18,158	19,715	19,770	20,143	20,682	20,027
MAIN	14,885	15,431	15,787	16,886	21,134	20,772	19,241	17,642	16,144	17,731	18,206
MARCA ^{2/}	6,132	7,949	8,286	8,409	7,977	7,434	6,723	6,045	7,080	5,656	5,057
NPCC ^{2/}	18,424	15,730	16,277	15,288	14,086	13,707	14,003	14,707	14,322	15,403	15,140
SERC	27,511	26,266	26,158	27,920	27,990	29,586	31,583	36,431	32,665	33,472	32,361
SWPP	18,314	19,473	22,170	23,872	25,282	25,230	27,970	28,864	30,238	30,245	30,971
7-Council Subtotal	127,798	127,740	133,520	136,416	141,293	141,629	149,094	153,787	151,838	153,027	152,574
WSCC ^{2/}	23,560	25,632	26,117	27,306	28,010	30,183	31,880	33,265	35,227	35,918	38,685
ERCOT	18,139	19,406	20,598	19,266	21,299	22,129	20,400	21,719	21,955	21,448	22,395
U.S. Total	169,497	172,778	180,235	182,988	190,602	193,941	201,374	208,771	209,020	210,393	213,654
<u>Reserve Capacity As A Percentage of Winter Peak Demand</u>											
ECAR	36.51	35.24	37.36	34.82	33.16	33.30	35.40	34.38	33.86	30.96	30.53
MAAC	67.59	65.20	60.49	57.46	58.04	52.53	55.06	53.38	52.58	52.26	49.02
MAIN	52.97	51.82	50.46	51.50	61.44	57.68	50.91	44.56	38.89	40.71	39.86
MARCA ^{2/}	36.87	44.60	43.78	41.83	37.58	33.11	28.28	24.11	26.79	20.33	17.30
NPCC ^{2/}	53.77	43.07	43.29	39.25	34.92	32.74	32.29	32.79	30.98	32.36	31.00
SERC	33.74	29.30	27.33	27.41	26.11	26.12	26.37	29.02	24.87	24.35	22.51
SWPP	64.60	66.35	70.85	71.71	71.30	66.63	69.96	68.06	67.32	63.59	61.54
Aver. 7-Councils	45.48	42.64	42.28	41.01	40.50	38.66	38.74	38.19	36.06	34.78	33.19
WSCC ^{2/}	33.62	35.03	33.88	33.79	33.23	34.39	34.85	34.89	35.41	34.66	35.97
ERCOT	84.35	88.09	88.37	78.68	82.65	81.33	71.9	72.55	69.92	64.88	64.51
Aver. U.S.	45.50	43.76	43.31	41.78	41.54	40.30	39.88	39.54	37.87	36.49	35.50

^{1/} Reserve capacity = Generating Capacity of Table 10 less Peak Demand of Table 9.

^{2/} U.S. Portion Only.

Table 12
COMPARISON OF ELECTRIC ENERGY PROJECTIONS^{1/}
MADE IN 1976, 1977, 1978 and 1979
BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES

For Year	1976 Gwh ^{2/}	Projections Annual Increase %	1977 Gwh	Projections Annual Increase %	1978 Gwh	Projections Annual Increase %	1979 Gwh	Projections Annual Increase %
1979	2,469,414	-	2,427,898	-	2,368,677	-	2,321,507	-
1980	2,617,501	6.0	2,579,351	6.2	2,504,732	5.7	2,442,046	5.2
1981	2,771,501	5.9	2,721,487	5.5	2,642,270	5.5	2,571,414	5.3
1982	2,932,066	5.8	2,875,821	5.7	2,784,656	5.4	2,696,036	4.9
1983	3,103,466	5.9	3,031,366	5.4	2,925,726	5.1	2,819,636	4.6
1984	3,293,219	6.1	3,197,148	5.5	3,079,822	5.3	2,956,771	4.9
1985	3,486,671	5.6	3,369,370	5.4	3,237,578	5.1	3,095,389	4.7
1986	N.R. ^{3/}	-	3,545,831	5.2	3,400,009	5.0	3,232,867	4.4
1987	N.R.	-	N.R.	-	3,561,399	4.8	3,374,949	4.4
1988	N.R.	-	N.R.	-	N.R.	-	3,526,173	4.5

^{1/} Annual energy required from all sources to satisfy the energy requirements of customers and supply transmission and distribution losses. It does not include the energy required for the pumping of pumped storage plants.

^{2/} 1 gigawatthour (Gwh) = 1,000,000 Kilowatthours (Kwh)

^{3/} N.R. = Not Reported. In each Council report energy projections are made only for a ten-year period.

Table 13
Accuracy of Energy Projections for 1978
Made in 1976, 1977 and 1978
By Regional Electric Reliability Councils

Council	<u>Annual Net Energy Requirement</u> ^{1/}			Actual 1978 - Gigawatthours ^{2/}	<u>(Projected) - (Actual)</u> = Difference			<u>Difference as Percent</u> <u>of Projected</u>		
	<u>Projected for 1978</u>									
	<u>in 1976</u>	<u>in 1977</u>	<u>in 1978</u>		<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
								- % -		
ECAR	333,800	372,500	388,300	369,108	14,692	3,392	19,192	3.98	0.92	5.20
MAAC	179,325	176,390	170,781	169,766	9,559	6,624	1,015	5.63	3.90	0.60
MAIN	176,895	173,489	169,642	168,808	8,087	4,681	834	4.79	2.77	0.49
MARCA	95,880	94,574	93,498	92,477	3,403	2,097	1,021	3.68	2.27	1.10
NPCC	207,854	205,613	200,327	198,918	8,936	6,695	1,409	4.49	3.37	0.71
SERC	501,259	486,554	470,672	452,750	48,509	33,804	17,922	10.71	7.47	3.96
SWPP	134,233	192,118	187,164	191,550	(7,317)	568	(4,446)	(3.82)	0.30	(2.32)
Sub-total	<u>1,729,246</u>	<u>1,701,238</u>	<u>1,680,324</u>	<u>1,643,377</u>	<u>85,869</u>	<u>57,861</u>	<u>36,947</u>	<u>5.23</u>	<u>3.52</u>	<u>2.25</u>
WSCC	443,974	437,779	423,862	410,135	33,839	27,644	13,727	8.25	6.74	3.35
ERCOT	<u>152,935</u>	<u>147,980</u>	<u>140,815</u>	<u>147,371</u>	<u>5,564</u>	<u>609</u>	<u>(6,556)</u>	<u>3.78</u>	<u>0.41</u>	<u>(4.45)</u>
U.S. Total	<u>2,326,155</u>	<u>2,286,997</u>	<u>2,245,061</u>	<u>2,200,883</u>	<u>125,272</u>	<u>86,114</u>	<u>44,118</u>	<u>5.69</u>	<u>3.91</u>	<u>2.00</u>

^{1/} Annual energy required from all sources to satisfy the energy requirements of customers and supply transmission and distribution losses. It does not include the energy required for the pumping of pumped storage plants.

^{2/} 1 gigawatthour = 1,000,000 kilowatthours
 () indicates negative number

Table 14
PROJECTED SCHEDULED INTER-REGIONAL SUMMER EXCHANGES OF CAPACITY
1979-1988
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
 Contiguous United States
 Summer Peak Period

Council	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
<u>Total Scheduled Exports (Megawatts)</u>										
ECAR	1,212	1,075	1,176	1,243	1,205	983	1,008	1,033	1,052	1,060
ERCOT	40	50	54	62	70	79	88	97	108	119
MAAC	0	0	0	0	0	0	0	0	0	0
MAIN	1,078	970	850	971	972	973	973	974	975	859
MARCA*	549	218	205	122	140	159	175	188	194	187
NPCC*	0	0	0	0	0	0	0	0	0	0
SERC	1,760	1,360	960	960	960	960	960	960	960	960
SWPP	3,377	4,238	3,690	3,558	3,582	3,442	3,286	3,503	3,307	2,911
WSCC*	0	0	0	0	68	0	0	100	100	0
<u>Total Scheduled Imports (Megawatts)</u>										
ECAR	418	408	408	318	318	245	245	245	245	245
ERCOT	155	145	550	720	575	1,025	630	808	690	685
MAAC	180	180	130	130	130	130	130	130	130	130
MAIN	2,200	2,046	2,106	1,566	1,254	1,254	1,254	1,124	1,120	808
MARCA*	205	691	780	728	791	720	718	817	811	699
NPCC*	1,268	1,254	1,256	1,256	1,258	1,260	1,261	1,062	864	866
SERC	300	300	300	300	300	300	300	300	300	300
SWPP	5,303	5,236	4,304	4,353	3,797	3,977	4,083	4,446	4,702	4,518
WSCC*	212	75	175	75	75	0	0	0	0	0

- Notes: 1. Each item in this table is the total, for each Council, of scheduled inter-utility inter-regional transactions, as reported under Item 2C of each Reliability Council Report. In some instances the data include capacity exchanges between members of a Council and non-members within the geographic boundaries of that Council, in addition to exchanges with utilities external to the Council boundaries.
2. The exchanges are non-coincident to the extent indicated by the following definitions:
 A Scheduled Import is a capacity transaction into a reporting party at the time of the importer's peak load that is at the time of reporting, or is expected to be, under contract or agreement for the period specified.
 A Scheduled Export is a capacity transaction out of a reporting party at the time of the exporter's peak load that is at the time of reporting, or is expected to be, under contract or agreement for the period specified.
3. These transactions are not intended to include those categorized as economy, maintenance, general purpose, non-displacement, or emergency.
- *U.S. portion of Council only.

Table 15
PROJECTED SCHEDULED INTER-REGIONAL WINTER EXCHANGES OF CAPACITY
1979-80 TO 1988-89
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
Contiguous United States

Winter Peak Period

	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89
	<u>Total Scheduled Exports (Megawatts)</u>									
ECAR	915	747	872	940	591	680	704	728	748	442
ERCOT	40	50	54	62	70	79	88	97	108	119
MAAC	0	0	0	0	0	0	0	0	0	0
MAIN	1227	1228	1228	1229	1230	1230	1231	1231	1232	1116
MARCA*	557	445	496	404	420	433	441	553	555	545
NPCC*	0	0	0	0	0	0	0	0	0	0
SERC	300	300	300	300	300	300	300	300	300	300
SWPP	4516	4731	4461	3760	3932	4319	3784	3997	3797	3488
WSCC*	0	0	0	0	0	0	0	100	0	0

Total Scheduled Imports (Megawatts)

ECAR	718	718	618	618	585	545	545	545	545	545
ERCOT	155	545	550	720	575	1025	630	803	690	685
MAAC	180	180	130	130	130	130	130	130	130	130
MAIN	1639	1775	1605	1305	993	993	993	863	860	548
MARCA*	196	183	131	129	125	122	119	216	110	98
NPCC*	455	456	456	458	460	461	262	64	66	67
SERC	1360	960	960	960	960	960	960	960	960	960
SWPP	3608	3577	3286	3538	3108	3409	3289	3652	3908	3818
WSCC*	305	175	175	75	0	0	0	0	0	0

- Notes: 1. Each item in this table is the total, for each Council, of scheduled inter-utility inter-regional transactions, as reported under Item 2C of each Reliability Council Report. In some instances the data include capacity exchanges between members of a Council and non-members within the geographic boundaries of that Council, in addition to exchanges with utilities external to the Council boundaries.
2. The exchanges are non-coincident to the extent indicated by the following definitions:
A Scheduled Import is a capacity transaction into a reporting party at the time of the importer's peak load that is at the time of reporting, or is expected to be, under contract or agreement for the period specified.
A Scheduled Export is a capacity transaction out of a reporting party at the time of the exporter's peak load that is at the time of reporting, or is expected to be, under contract or agreement for the period specified.
3. These transactions are not intended to include those categorized as economy, maintenance, general purpose, non-displacement, or emergency.

*U.S. portion of Council only.

Table 16
PROJECTED NET SCHEDULED INTER-REGIONAL EXCHANGES OF CAPACITY, SUMMER AND WINTER
1979-1988
BASED ON DATA REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS^{1/}
TO THE DEPARTMENT OF ENERGY - APRIL 1, 1979
 Contiguous United States

		<u>Summer Peak Period-Net of Scheduled Imports and Exports in MW^{2/3/}</u>								
<u>Council</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>
ECAR	- 794	- 667	- 768	- 925	- 887	- 738	- 763	- 788	- 807	- 815
ERCOT	115	95	496	658	505	946	542	711	582	566
MAAC	180	180	130	130	130	130	130	130	130	130
MAIN	1122	1076	1256	595	282	281	281	150	145	- 51
MARCA*	- 344	473	575	606	651	561	543	629	617	512
NPCC *	1268	1254	1256	1256	1258	1260	1261	1062	864	866
SERC	-1460	-1060	- 660	- 660	- 660	- 660	- 660	- 660	- 660	- 660
SWPP	1926	998	614	795	215	535	797	943	1395	1607
WSCC *	212	75	175	75	7	-0-	-0-	- 100	- 100	-0-

		<u>Winter Peak Period-Net of Scheduled Imports and Exports in MW^{2/3/}</u>								
<u>Council</u>	<u>1979-80</u>	<u>1980-81</u>	<u>1981-82</u>	<u>1982-83</u>	<u>1983-84</u>	<u>1984-85</u>	<u>1985-86</u>	<u>1986-87</u>	<u>1987-88</u>	<u>1988-89</u>
ECAR	- 197	- 29	- 254	- 322	- 6	- 135	- 159	- 183	- 203	103
ERCOT	115	495	496	658	505	946	542	711	582	566
MAAC	180	180	130	130	130	130	130	130	130	130
MAIN	412	547	377	76	- 237	- 237	- 238	- 368	- 372	- 568
MARCA*	- 361	- 262	- 365	- 275	- 295	- 311	- 322	- 337	- 445	- 447
NPCC *	455	456	456	458	460	461	262	64	66	67
SERC	1000	660	660	660	660	660	660	660	660	660
SWPP	- 908	-1154	-1175	- 222	- 824	- 910	- 495	- 345	111	330
WSCC *	305	175	175	75	-0-	-0-	-0-	- 100	-0-	-0-

^{1/} From Item 2C of the Council reports

^{2/} Imports - Exports = Net

^{3/} The net of scheduled imports and exports for any Council does not necessarily occur at the same time as the net for any other Council. Therefore a total for all Councils, in any peak period, would not be a meaningful quantity.

*U.S. portion of Council only.

Table 17
PROJECTED BULK POWER TRANSMISSION LINES 1979-1988
SIGNIFICANT FOR INTERCONNECTED OPERATION
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY - April 1, 1979
 Contiguous United States

Miles of Line at Each Voltage Level^{1/}

<u>Council</u>	<u>230 Kv</u>	<u>345 Kv</u>	<u>500 Kv</u>	<u>765 Kv</u>	<u>Other</u>	<u>Total</u>
ECAR	310	3503	327	1801	-0-	5941
ERCOT	-0-	3960	-0-	-0-	-0-	3960
MAAC	1198	33	558	0	-0-	1789
MAIN	-0-	1860	55	-0-	-0-	1915
MARCA*	1384	2844	854	0	1895 ^{2/}	6977 ^{3/}
NPCC*	44	1342	-0-	89	685 ^{4/}	2160
SERC	6052	-0-	3631	767	42 ^{5/}	10492
SWPP	2406	4613	1272	-0-	-0-	8291
WSCC*	4587	4278	7858 ^{6/}	-0-	2399 ^{7/}	19122
Total	15981	22433	14555	2657	5021	60647

1/ All voltages are A.C. unless otherwise stated.

2/ 973 miles at 161 Kv and 922 miles at 115 Kv.

3/ In addition, studies are underway for a 632-mile line at either 500 Kv or $\pm$ 450 Kv D.C.

4/ 138 Kv and 115 Kv.

5/ 138 Kv

6/ New construction; does not include 242 miles of existing 287 Kv line to be converted to 500 Kv in 1980 and 1986.

7/ Includes 356 miles at 115 Kv and 161 Kv; 2042 miles at 1000 Kv D.C.; one mile at 287 Kv.

* U.S. portion of Council only.

General Description of The Regional Electric Reliability Councils

1. History of Reliability Councils

The Regional Electric Reliability Councils were formed during the period 1963 through 1969.^{1/} The Federal Power Commission in its comprehensive report on power failures^{2/} urged the electric utility industry to organize strong regional organizations in order to coordinate planning for reliability and economy. The industry formed 12 such groups. The 12 later were reduced to nine when TVA, the Virginia-Carolina Group, the Southern Company and the Florida utilities joined together to form the Southeastern Electric Reliability Council (SERC). Maps of the current council areas are attached. Shortly after the regional councils were formed, they joined together to establish the National Electric Reliability Council (NERC).^{3/} Since its formation NERC has acted as the national spokesman of the electric utility industry in matters regarding reliability of bulk power supply. Annually, since 1971, a committee of NERC has issued a report discussing the reliability of power supply of North America. In addition NERC committees have published other reports, dealing with fuel supply for the coming decades and with inter-regional transfers of electric energy (among other things).

^{1/} The predecessor of Mid-Continent Area Reliability Coordination (MARCA) was Mid-Continent Area Power Planners (MAPP), an industry group organized in February 1963. Mid-America Interpool Network (MAIN) was formally organized in November 1964.

^{2/} Prevention Of Power Failures - A Report To The President By The Federal Power Commission, July 1967, Vol. 1 p. 4.

^{3/} NERC was established by an agreement dated June 1, 1968, among twelve regional organizations that had been previously formed to improve electric bulk power supply reliability in the areas served by their utility members.

2. Federal Power Commission - Council Relationship^{1/}

The context of the Commission-Council relationship is set by Section 202(a) of the Federal Power Act^{2/} and by the Commission's Statement of Policy regarding Reliability and Adequacy of Electric Service, issued June 25, 1969 under Docket R-362. In that Statement the Commission added a new section (para. 2.11) to Subchapter A, Chapter I of Title 18 of the Code of Federal Regulations. The new section read (in part):

(a) Participation of federal personnel in regional reliability councils. The Federal Power Commission's responsibilities under Section 202(a) of the Federal Power Act, to promote and encourage voluntary efforts by the various segments of the electric utility industry to coordinate their activities, can best be carried out if the regional reliability councils or organizations of the utilities in various parts of the country permit participation by staff personnel of the Federal Power Commission. Participation on a non-voting basis will not inhibit appropriate discussion, planning or review of the members of the regional councils. Accordingly, the regional reliability or coordination councils and any other systems or groups engaging in similar activities are requested promptly to permit non-voting participation of FPC staff personnel.

(b) Participation of State personnel in regional reliability councils. It is the policy of the Commission that staff personnel of the State regulatory agencies of the particular region be permitted to participate in the regional reliability or coordination councils on the same basis as Commission personnel.

^{1/} All references to the Federal Power Commission are to read in a historical context. The Department of Energy Organization Act replaced FPC with the Federal Energy Regulatory Commission and resulted in the transfer of Section 202(a) of the Federal Power Act to the jurisdiction of the Economic Regulatory Administration.

^{2/} Section 202(a) reads:

"For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. (See Following Page)

2/ (Continued)

Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations [49 Stat. 848; 16 U.S.C. 824a(a)]

Following a rule-making proceeding in which comments were invited from the utility industry, state regulatory commissions and other interested parties, the Commission issued Order 383-2 on April 10, 1970 under Docket R-362. Appendix A of Order 383-2 specified 10 items intimately involved with the planning and operation of reliable bulk power supply, to which the councils were requested to provide annual responses. The first response was filed September 1, 1970. Additional responses in accordance with the order have been filed annually on April 1, of each year. In March 1973 the Commission modified Appendix A through issuance of Order 383-3 and its Appendix A-1, which added two items to the list of those to which the councils were requested to reply. Order 383-4, which further revised the informational list of items, was issued in 1976 and the first response under that Order was filed April 1, 1977.

In the interests of obtaining more useful information and standardizing the reporting format, the Commission proposed a revision (Appendix A-2) of Order 383-4. The proposed changes were discussed in a series of meetings between representatives of the National Electric Reliability Council and FPC staff members and a revised format was agreed upon. The Secretary of the Department of Energy was also advised of the proposed changes on September 30, 1977 and his early consideration was urged. Substantially that format was followed by the Councils in their reports of April 1, 1978 and April 1, 1979, which were filed with the Department of Energy (ERA).

Much of the Commission's knowledge of the year to year status of electric planning was derived from Council responses to the "383" series of orders and attendance by Bureau of Power staff engineers at meetings of

the Council Executive Committees, Council Planning Committees and Council Operating Committees. Staff personnel of state regulatory commissions attended the meetings also, but state commission participation was less in some regions than in others. Budgetary difficulties appeared to exercise a restraining effect on participation by some of the states.

At the meetings, the representatives of the council's utility members discuss experienced and projected demands for power, operating difficulties, reliability criteria, planning of future generating units and transmission lines and other matters related to system planning and operation. The Commission attempted to intensify state participation through the formation of Federal-State Coordinating Committees that would parallel the state coverage of the Reliability Councils. At the meetings of these Committees, Bureau of Power staff representatives would discuss regulatory problems with State commission staff personnel. The Department of Energy Organization Act lends support to activities of this nature.

It is appropriate to note that each of the nine reliability councils is a voluntary association of electric utilities within a geographic area. The council boundaries were established by the utilities involved on the basis of contiguous service areas, commonality of interests and historic working relationships.

Each council has an administrative office and a small staff, which is responsible for (among other duties) preparation of the council's response to Order 383-4.^{1/} Much of a council's coordinating activity is carried out through standing and special committees. Committee members are representatives of the utilities in the council areas. The members of these committees, by virtue of their being engineers intimately familiar with power system planning on the part of the utilities they represent,

^{1/} The response is now identified as the Council's Coordinated Bulk Power Supply Program, reported to the Department of Energy on April 1.

are qualified to propose, review and discuss bulk power supply planning on a large-scale, long-range coordinated basis. For the same reason they are qualified to review, evaluate, study and take measures to implement such practices as lend themselves to coordinated operations. The councils and their committees concern themselves only with reliability and adequacy of power supply and do not involve themselves in rate matters.

The major committees of the reliability councils are the following:

National Electric Reliability Council (NERC)

Technical Advisory Committee
Interregional Review Subcommittee

East Central Area Reliability Coordination Agreement (ECAR)

Coordination Review Committee
Liaison Committee (works with utilities in the ECAR area who are not ECAR members)

Electric Reliability Council of Texas (ERCOT)

Technical Advisory Committee

Mid-Atlantic Area Council (MAAC)

MAAC-Area Coordination Committee
PJM Interconnection Office
PJM Planning & Engineering Committee

Mid-America Interpool Network (MAIN)

Operating Committee
Transmission Task Force
Engineering Committee

Mid-Continent Area Reliability Coordination Agreement (MARCA)

Design Review Committee
Operating Review Committee

Northeast Power Coordinating Council (NPCC)

System Design Coordinating Committee
Operating Procedure Coordinating Committee

Southeastern Electric Reliability Council (SERC)

Technical Advisory Committee
Florida Subregion
Southern Subregion
TVA Subregion
Virginia-Carolina (VACAR) Subregion

Southwest Power Pool (SWPP)

No Committee Structure Reported

Western Systems Coordinating Council (WSCC)

Planning Coordination Committee
Operations Committee

Inter-Council Committees

MAAC-ECAR-NPCC-VACAR Joint Inter-Area Review Committee

3. Council-Power Pool Relationships

Electric utilities have in many instances interconnected their facilities to obtain better economy of operation, greater reliability and the benefits of decreased investment in generating plant. Each interconnection between utilities is formalized in a contract wherein each party agrees to undertake specified responsibilities. The manner of operation of the interconnection is described in sufficient detail to make it viable. When the agreement is comprehensive enough that the utilities agree to share their reserve capacity, with each party being assigned a specific magnitude of reserve, and agree to interchange power and energy, the contract is usually called a "pooling agreement". The parties are then said to be members of a "power pool". Every interconnection agreement between utilities, whether or not it is extensive enough to be called a "pooling agreement", is filed with the FPC (now FERC) as a "Rate Schedule".

A council has no jurisdiction or authority over any utility members or over any power pools within its area. The councils act as coordinating organizations, to provide in each region a forum for discussing common problems, for review of coordinated planning and for discussion of coordinated operating practices on the part of the electrical utilities and for general interchange of information. The members of the councils are electric utilities. Power Pools as such are not members of the councils although their component utilities are council members.

4. Non-members

Not every electric utility is a member of a Reliability Council, but many of the non-members cooperate in providing planning information to be included in the Coordinated Bulk Power Supply Program report. In New England, for instance, the following utilities have chosen not to join the Northeast Power Coordinating Council (NPCC) but do furnish the data needed to make the Coordinated Program report meaningful:

- Bangor Hydro Electric Co.
- Fitchburg (Mass.) Gas & Electric Light Dept.
- Holyoke (Mass.) Gas & Electric Dept.
- Hudson (Mass.) Light & Power Dept.
- Ipswich (Mass.) Municipal Light Dept.
- Maine Public Service Co.
- Marblehead (Mass.) Municipal Light Dept.
- Newport (R.I.) Electric Corp.
- Norwalk (Conn.) Second Taxing District
- Norwich (Conn.) Dept. of Public Utilities
- Peabody (Mass.) Municipal Light Dept.
- Shrewsbury (Mass.) Electric Light Dept.
- Taunton (Mass.) Municipal Light Dept.
- Wallingford (Conn.) Municipal Electric Dept.

5. Financing

Financing of the Reliability Councils is entirely a function of the utility members. Each member shares in the cost of operating the Council and meeting its budgetary commitments. There is no subsidy or contribution from the Federal or state governments.

6. What the Federal Power Commission Asked The Councils To Do

The Federal Power Commission through its 383 series of Orders requested the councils to obtain from each of their member utilities such data as is needed to respond to the Appendix of the latest Order. Smaller utilities, not members of a council, were requested to supply data thru the councils, so that comprehensive regional reports could be prepared. Each council compiles the information furnished in a single report and supplies it annually to the Economic Regulatory Administration and to the state commissions within the area of each council. Some councils print additional copies and make them available to other governmental agencies. The annual reports project in detail the loads and resources for the council area for 10 years in advance and in general terms for a further 10 year period. Each generating unit projected for completion within the 10-year period beginning with the year of the report is listed and identified as to owner, capacity, date of initial operation, fuel type and site to the extent the information is available. Peak demands are projected for summer and winter, with annual net energy requirements, for each year in the decade; some councils present this data for sub-groups within the council area as well as for the entire region. Information is also given concerning transmission line construction, load flow studies and other factors pertinent to coordinated planning and operation.

In addition to the annual reliability reports, the FPC from time to time requested the assistance of the councils in dealing with large scale problems affecting the entire electric utility industry. For instance the Commission obtained council assistance in collecting data concerning the effect of daylight savings time extension several years ago; the Commission

obtained the cooperation of the councils in organizing a study of utility system contingency planning; the Commission used data assembled by the Western Systems Coordinating Council (WSCC) in preparing (with the assistance of the then Federal Energy Administration) a report on the drought situation in the West; the Commission obtained the cooperation of the Councils in encouraging utilities to install underfrequency load shedding arrangements.

Other studies related to bulk power supply reliability, in which the Commission found it convenient and useful to have reliability council assistance were the following:

A survey in 1969 of utility practices relating to design, operation and maintenance of power system facilities. The survey was performed by NERC. Some of the information was incorporated in the Commission's 1970 National Power Survey, and a report was issued by NERC in April 1970 titled "Practices Affecting Reliability of Bulk Power Supply".

An examination of the power situation in the Pacific Southwest Area - the Western Systems Coordinating Council performed the study and issued a report dated December 3, 1971, titled "The Effects of Curtailment of Coal-Fired Plants In the Pacific Southwest Area".

At the request of FPC and FEA, NERC established an Energy Transfer Study Task Force to examine the capability of the inter-connected systems east of the Rockies to make inter-regional transfers of electric energy for the purpose of conserving oil and natural gas. A report was issued by the Task Force, in October 1975,

titled "A Study of Interregional Energy Transfers, 1975-76 Winter". A second report was issued in May 1976 titled "A Study of Interregional Energy Transfers For The Year 1980".

7. What Reviews Are Made

The Commission staff reviewed the nine council reports received annually, summarized the planning data and load forecasts and published brief analyses with summaries of the data. ERA has continued this practice and makes its reports available to governmental agencies, Members of Congress, industry, individuals and organizations who request information, to assist them in various activities related to electric power supply adequacy. DOE and the Environmental Protection Agency make extensive use of the generating unit data, transmission line data and load forecasts provided by the councils in the Coordinated Program Reports. In addition, the council reports are used as information sources in responding to specific inquiries from the Congress and the public.

8. Follow Up on The Reports

When items in the reports indicate some investigation is required the matter is discussed with the appropriate council office and the specific utilities involved. Usually the Economic Regulatory Administration's Regional Offices discuss what appear to be discrepancies or unusual items in the reports with the appropriate Council office. The Washington Staff may also enter the discussions.

For instance, FPC Bureau of Power staff discussed with the councils the load forecasts provided in response to the 383-series of orders. The councils were urged to amplify the numerical data with information as to

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the bases of the forecasts: the assumptions as to energy conservation, fuel use, the regional and national economy, the effects of price changes and other factors. FPC staff on many occasions discussed with Council personnel the questions of reserve generating capacity and reliability.

On numerous occasions, FPC staff used the Council offices as authoritative regional centers for obtaining responses to specific questions related to regional power supply when the necessary information was not contained in the routine reports filed by utilities. ERA and the Councils cooperate in the same way currently.

**SUBREGION BOUNDARIES OF THE
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)**

OCTOBER 1, 1973

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

U.S. GENERATING CAPACITY
AS OF JUNE 30, 1979

The approximate composition of electric generating capacity in the contiguous United States is shown in the following several tables. The megawatts of capacity associated with each type of fuel may differ to some extent from the data reported by the Regional Electric Reliability Councils in their April 1, 1979 Coordinated Planning Reports. There are several reasons for the differences:

1. The data herein is taken from the Energy Information Administration Generating Unit Reference File (GURF), which reports only "Nameplate" and "Net dependable capability". The "net dependable capability" reported is in some instances the "nameplate" data (where net dependable capability was not reported by a respondent utility).
2. The time frame of the GURF data and the Council data is not exactly the same.
3. The GURF data includes, insofar as possible, all utilities in the U.S. The council reports do not include a number of small systems that did not report their generating capability to the Councils.
4. Large statistical aggregations of purportedly identical data, collected at different times by means of different reporting forms and processed by different organizational entities, are subject to dissimilar types of errors and judgmental decisions in reporting, transcription and aggregation.

5. The total generating capacity shown by the GURF data herein differs by only a small percentage from the total reported by the councils. The time-consuming and laborious task of isolating, and adjusting the differences was not undertaken at this time because of time constraints. However, a continuing effort is being made to eliminate errors, inconsistencies and incorrect (and incomplete) reporting in the sources used for the GURF records. The purpose of this Appendix is only to establish a general profile of U.S. generating capacity as of mid-1979.

Contiguous U.S. Fossil Steam Generating Capacity
As of July 2, 1979
(In Megawatts)

Primary Fuel	Alternate Fuel						Total MW
	Coal	Oil	Gas	Multiple ^{1/}	Un-Specified ^{1/}	None	
Coal	0	10,600	21,977	282	1,249	178,777	212,885
Oil	8,213	2,256 ^{2/}	43,019	496	245	44,116	98,345
Gas	925	47,457	-0-	815	53	13,615	62,865
Other ^{3/}	16	10	-0-	-0-	-0-	14	40
Multiple ^{1/}	29	-0-	-0-	1,192	-0-	530	1,751
Unspecified ^{1/}	-0-	-0-	-0-	-0-	590	-0-	590
Total	9,183	60,323	64,996	2,785	2,137	237,052	376,476

^{1/} It is believed that these categories result from a mis-understanding of the reporting requirements by the respondents. Continuing efforts are being made to resolve this problem.

^{2/} Oil of a grade different from the primary fuel

^{3/} Wood waste, etc.

Contiguous U.S. Combustion Turbine Generating Capacity
As of July 2, 1979
(In Megawatts)

Primary Fuel	Alternate Fuel					Total MW
	Oil	Gas	Multiple ^{1/}	Un- Specified ^{1/}	None	
Oil	544 ^{2/}	9,953	315	217	20,488	31,517
Gas ^{3/}	4,735	-0-	-0-	60	2,097	6,892
Other ^{1/}	92	2,296	66	0	1,308	3,762
Multiple ^{1/}	-0-	-0-	-0-	-0-	5	5
Unspecified ^{1/}	-0-	-0-	-0-	105	-0-	105
Total	5,371	12,249	381	382	23,898	42,281

^{1/} It is believed that these categories result from a misunderstanding of the reporting requirements by the respondents. Continuing efforts are being made to resolve this problem.

^{2/} Oil of a grade different from the primary fuel.

^{3/} Kerosene, Jet Fuel, Liquified Propane Gas.

Contiguous U.S. Diesel Generating Capacity

As of July 2, 1979

(In Megawatts)

Primary Fuel	Alternate Fuel				Total MW
	Oil	Gas	Unspecified	None	
Oil	8	1,119	101	8,862	10,090
Gas	537	-0-	-0-	86	623
Unspecified	1	-0-	767	0	768
Total	546	1,119	868	8,948	11,481

Contiguous U.S. Hydro Generating Capacity

As of July 2, 1979

(In Megawatts)

Conventional	65,930
Pumped Storage	11,651
Total	77,581

Contiguous U.S. Combined Cycle Generating Capacity

As of July 2, 1979

(In Megawatts)

4000 MW (Fuel type not reported)

Contiguous U.S. Nuclear Generating Capacity
As of July 2, 1979
(In Megawatts)

48,805 MW

Contiguous U.S. Geothermal Generating Capacity
As of July 2, 1979
(In Megawatts)

608 MW

Contiguous U.S. Total Generating Capacity
As of July 2, 1979

	<u>Megawatts</u>	<u>% of Total</u>
Fossil Steam	376,476	67.080
Combustion Turbine	42,281	7.534
Diesel & Jet Engine	11,481	2.046
Combined Cycle	4,000	0.713
Conventional Hydro	65,930	11.747
Pumped Storage	11,651	2.076
Geothermal	608	0.108
Nuclear	48,805	8.696
Total	561,232	100.000

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WASHINGTON, D.C. 20585

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