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Electric Power Supply and Demand for the Contiguous United States 1980-1989

June 1980

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

MASTER

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Washington, D.C. 20585

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PURPOSE

The purpose of this report is to present a limited review of the outlook for electric power supply and demand during the period 1980-1989. This report considers only the adequacy and reliability aspects of bulk electric power supply in the contiguous United States. We recognize that the economic, financial and environmental aspects of electric power system planning and the distribution of electricity (below the transmission level) are topics of prime importance, but they are outside the scope of this report.

Report Organization

Sections I through X deal generally with electric power supply and adequacy as projected for the nine Reliability Council areas and the total contiguous United States. Section XI discusses those topics as projected in detail for each of the 29 Electric Regions (sub-areas of the nine Council areas) in the contiguous United States.

A glossary of terms used in the report follows Section XI, and is followed by two appendices. Appendix A describes the structure of the Reliability Councils. Appendix B lists the utilities for which data is included in this report.

This copy of the report is a preliminary issuance, circulated in order to make available quickly the conclusions and data of the study. The final version of the report may be published shortly after all data have been checked for accuracy. While minor changes and corrections may be made, we are sure that no changes in the conclusions and general text of the report will be needed.

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SECTION

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- A. Mid-Continent Area Power Pool (MAPP)

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- A. New England Power Pool (NEPOOL)
- B. New York Power Pool (NYPP)

7. SERC

- A. Florida Coordinating Group (FCG)
- B. Southern Company (SoCo)
- C. TVA
- D. Virginia-Carolinas (VACAR)

8. SPP

- A. Middle South Utilities (MSU)
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- C. Missouri-Kansas Pool (MOKAN)
- D. Oklahoma

9. WSCC

- A. Rocky Mountain Power Area (RMPA)
- B. Northwest Power Pool (NWPP)
- C. Arizona-New Mexico (AZ-NM)
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- E. Northern California-Nevada (NC-N)
- F. Idaho-Utah (included in NWPP)

Glossary

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Participants in this Report

GENERAL CONCLUSIONS

- o Load growth for 1980-1983 is projected to average 2.1% annually for energy (Mwh) and in the range of 2.1% to 2.9% annually for summer peak demand (Mw). These projections, made by the Division of Power Supply and Reliability, are about half the increases projected by the Reliability Councils.
- o Generating capacity reserve margins, based on the loads and construction schedules projected by the Reliability Councils, are adequate to provide reliable service in most areas of the contiguous United States for the period 1980-1989. Reserve margins in some Electric Regions (sub-areas of the Council areas) however, may be insufficient over specific time intervals to assure reliable electric service in those Regions.
- o Failure of nuclear and coal-fired generating units to meet projected schedules for commercial operation could have a serious negative effect on power supply reliability and adequacy in many areas.
- o To assure reliable energy supply and provide for significant reduction of fuel oil consumption, every effort should be made to maintain the current schedules for construction and licensing of the following nuclear units. All of these units are scheduled for commercial operation by the end of 1981.

Diablo Canyon 1
Diablo Canyon 2
San Onofre 2
LaSalle County 1
LaSalle County 2

Farley 2
McGuire 1
Summer 1
Watts Bar 1
Sequoyah 2

- o The following coal-fired units are considered prime candidates for accelerated completion and operation:

Brandon Shores 2	California Coal 2
Brandon Shores 1	Coho 1
Sears Island	H. Allen 1
Seward 7	H. Allen 2
California Coal 1	H. Allen 3

- o The reserve margin projections of Section XI indicate that some Electric Regions may experience difficulty in supplying customer demands at the time of summer peak load in 1980. Since the major difficulty is expected to be a lack of sufficient generating capacity (including currently scheduled capacity purchases from other regions), special measures to maintain system viability may be necessary. These measures could include: emergency purchases from other regions, voltage reductions, appeals to consumers to reduce their use of electric power, disconnection of contractually interruptible loads. Those regions in which reliability problems may occur are listed in Table A, below.

Table A

ELECTRIC REGIONS WITH POSSIBLE
CAPABILITY PROBLEMS PROJECTED
FOR THE 1980 SUMMER PEAK

<u>No.</u>	<u>Electric Region Name</u>	<u>% Reserve 1/</u>	<u>Council in Which Region is Located</u>
12	VACAR	(1.7)	SERC
10	Gulf States Utilities Group	1.6	SWPP
28	Northern California-NEV	2.3	WSCC
11	TVA	5.4	SERC
7	Florida Coordinating Group	6.6	SERC

() = Negative Number

1/ After allowance for scheduled maintenance, inoperable capacity, and scheduled exchanges with other electric regions, all as projected by Council and utility report, and allowance for probable forced outages as computed by Staff.

- o For the Electric Regions not listed in Table A, projected generating capacity appears to be adequate for meeting contingencies of the kind normally encountered. However, even for these regions, unusual occurrences resulting in damage to transmission system facilities (e.g., storms, fires) could adversely affect the network's ability to supply capacity to the load centers for brief periods of time.

I. SUMMARY

I.1 Highlights

- o Power supply reliability in most regions of the contiguous U.S. is expected to be adequate for the period 1980-1985, but problems exist in some areas.
- o Requirements for electric energy and peak demand can reasonably be expected to increase at a rate in the range of 2.1% to 2.9% per year through the end of 1983.
- o Failure to have in operation (as now scheduled) those nuclear units slated for completion by the end of 1985 could result in the use of some 700 million additional barrels of oil.
- o The timely licensing and construction of nuclear power plants, consistent with all applicable safety and environmental considerations, could play a key role in the improvement of power supply adequacy and reliability in several regions.
- o Acceleration of coal unit construction could save some 70 million barrels of oil by the end of 1989.

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

Electric Regions in the United States

June 1, 1980 *

Reliability Council

- ECAR -East Central Area Reliability Coordination Agreement
- ERCOT -Electric Reliability Council of Texas
- MAAC -Mid-Atlantic Area Council
- MAIN -Mid-America Interpool Network
- MARCA -Mid-Continent Area Reliability Coordination Agreement
- NPCC -Northeast Power Coordinating Council
- SERC -Southeastern Electric Reliability Council
- SWPP -Southwest Power Pool
- WSCC -Western Systems Coordinating Council

* First revision of July 1, 1979 map.

Electric Region	Identification
1	Allegheny Power System (APS)
2	American Electric Power System (AEP)
13	Central Area Power Coordination Group (CAPCO)
14	Cincinnati, Columbus, Dayton Group (CCD)
15	Kentucky Group
16	Indiana Group - All Indiana Utilities except I&M Electric Co.
18	Michigan Electric Coordinated Systems (MECS)
23	Texas Interconnected Systems Group (TIS)

5	MAAC	Pennsylvania-New Jersey-Maryland Interconnection (PJM)
6	MAIN	Commonwealth Edison Co., Illinois-Missouri Group (ILLMO)
17		Wisconsin-Upper Michigan Systems Group (WUMS)
19		
20	MARCA	Mid-Continent Area Power Pool (MAPP)
21		
22		
23	NPCC	New England Power Pool (NEPOOL)
24		New York Power Pool (NYPP)
25		
26		
27		
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29		
30		
31		

7	SERC	Florida Coordination Group (FCG)
8		Southern Company Group
9		Tennessee Valley Authority Group (TVA)
10		Virginia-Carolinas Group (VACAR)
11		
12		
13	SWPP	Middle South Utilities Group
14		Gulf States Group
15		Missouri-Kansas Group (MOKAN)
16		Oklahoma Group
17		
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I.1

I.2 - DISCUSSION

The growth rates for peak demand, generating capability and electric energy requirements, as projected by the Regional Electric Reliability Councils ^{1/} in their April 1, 1980, Coordinated Bulk Power Supply Programs, except for the Texas Region, are less than the rates projected in 1979. The Division of Power Supply and Reliability concurs in the general expectation of a lower rate of growth for electric power, without necessarily endorsing the specific forecasts reported by the Councils. Reliability Council area-wide reserves, as projected, are adequate for all Councils except MARCA. MARCA's summer reserve margin appears low from 1986 on, and in 1989 becomes too low to assure reliable service. The low projected reserves of several Electric Regions are discussed in Section XI.

For the contiguous U. S. as a whole, the average annual rate of increase of salient power system characteristics as projected by the Councils in their reports dated April 1, 1979 and April 1, 1980, are compared in the table below:

Table I.2.1

	Projected Average Annual % Increase	
	<u>1978-88</u>	<u>1979-89</u>
Summer Peak Demand	4.9	4.3
Winter Peak Demand	4.9	4.6
Annual Net Energy Requirement	4.8	4.2
Capability at Time of Summer Peak	4.1	3.6
Capability at Time of Winter Peak	4.2	3.7

1/ See Appendix A for a general description of the Regional Electric Reliability Councils.

Projected increases in capability, peak demand and energy requirements differ among the NERC Council Regions ^{1/}. The ten-year energy and demand growth rates as projected by each Council in 1979 and in 1980 are shown in the table below. ERCOT is the only Council which currently projects a higher rate of growth than was projected a year earlier.

Table I.2.2

Projected Average Annual % Increase

	Annual Energy		Summer Peak Demand	
	1978-88	1979-89	1978-88	1979-89
MAAC	3.5	3.2	3.3	2.9
NPCC	3.5	2.1	3.4	1.9
ECAR	4.5	3.8	4.4	4.0
MAIN	4.7	4.0	4.8	4.2
WSCC	4.8	4.5	5.0	4.5
SERC	4.8	4.6	5.7	4.5
ERCOT	4.9	5.2	5.2	5.6
MARCA	5.5	4.8	5.6	5.5
SWPP	6.2	5.3	6.0	5.6

Summer peaking is expected to continue as a characteristic of total U.S. demand, although some Council regions do expect winter peaks. For summer 1989, total U.S. demand is expected to be 610,682 Mw ^{2/}; this is an increase of 209,526 Mw over the summer 1979 value of 401,156 Mw. The generating capability to supply the 1989 summer peak is projected by the Councils to reach 778,058 Mw. In summer 1979, the U.S. generating capability was 544,560 Mw. Although the national installed (planned) reserve margin is not a valid criterion of reliability, its magnitude is nevertheless of interest. The summer 1979 reserve margin was 35.8%; the margin is expected to drop to 27.4% by summer 1989.

^{1/} "NERC Council Regions" refers to the respective areas of the nine Regional Electric Reliability Councils. "Electric Regions" refers to the 29 areas which ERA has established as subdivisions of the nine Reliability Council areas.

^{2/} Non-coincident sum of Council area peaks.

On the basis of the capacity, demand and energy requirements currently projected by the Reliability Council reports, it appears that adequate electric power will be available in most Electric Regions through the end of 1989. Critical to this assessment is the assumption that the rate of load growth is no greater than the Council reports indicate. If the average annual rates of peak demand and energy growth should be greater than projected, power system reliability will, in general, decline. For instance, an average annual increase of 4.5% in summer peak demand, instead of the 4.3% projected, would cause the national summer installed (planned) reserve margin to drop to 24.9% in 1989. That is, an increase of 0.2% in the average annual rate of demand growth has a cumulative negative effect of 2.5% on reserve margin by 1989. The level to which reliability would fall will be a function of the magnitude of the demand increase, provided construction of generating capacity is maintained at the pace projected in the April 1, 1980 Council reports.

The matter of projected additions to the bulk power supply system is of great concern to the Department of Energy. Adequacy of power supply is strongly dependent on the maintenance of a prudent balance between projected demand and projected supply, with due allowance for the uncertainties of the future. The reserve margins projected by the Regional Reliability Councils rely on continued construction, and completion on schedule, of hundreds of new generating units through 1989. Of the projected units, 86 totalling nearly 94,000 MW, are nuclear. In reviewing the dates projected in the Council Reports for completion of these units, we have concluded that many of the in-service dates are highly optimistic. Our appraisal indicates the strong possibility that 53 of the nuclear units scheduled for operation by the end of 1985, with a total capability of about 57,000 Mw, are not likely to be operational on the dates given in the Regional Council reports. Failure of these units to be available as scheduled will degrade the projected reserve margins, (as discussed in Section VII) and will result in increased consumption of oil and gas. Coal-fired units comprise a large portion of future capacity construction, and delays in completion of these units will also degrade the prospective reserve margins and will increase reliance on scarce fuels.

Fuel supply is of course a critical factor in the planned operation of generating units. The Reliability Council reports consider fuel only to the extent of identifying the primary and alternate type of fuel for existing and projected generating units. No estimate is given of the fuel quantities needed. It is necessary to point out that any restrictions on primary energy supply (nuclear, coal, oil, natural gas, water) have a negative impact on the ability of a utility system to operate its generating units. Coal storage piles and oil storage tanks are intended to smooth out temporary fluctuations in the flow of fuel from source to generating unit. They cannot cope with long-term restrictions on fuel supply. Extended and widespread stoppage, such as results from strikes and embargoes, can disrupt the orderly operation of even the best-planned power system. Both the reliability and the economy of system operation are reduced when adequate fuel of the type for which generating units are designed is not available.

Electric energy supply from a power system is to a certain extent independent of interruptions in supply of a specific type of fuel, provided alternate fuel sources are available and can be utilized. For instance, increased use of coal-fired and nuclear units can compensate to a limited degree for reduced energy production by oil-fired units. The amount of compensation depends on the "mix" of unit types in the area with an oil-supply shortage, transmission interconnections with other areas, the current degree of loading on coal-fired and nuclear capacity and other factors. In November 1979, as an example, oil fuel provided 12.9% of the electric energy generated in the contiguous U.S. But this average value masks the regional variations: in the six-state New England region, oil provided 53.6% of the regional electric generation whereas in the area covered by Ohio, Indiana, Illinois, Michigan and Wisconsin oil provided only 5.4% of the electric generation. In the total Washington-Oregon-California area, 28.9% of electric energy was provided by oil, but in Arkansas-Louisiana-Oklahoma-Texas, only 4.0% of electric energy production was oil-based.

Except for the Northwest Power Pool (NWPP) area, adequacy of energy supply appears reasonably secure in the various electric regions, if fuel supply is provided as now contemplated for projected units, at least through the summer of 1985. In the NWPP region, the large amount of hydro capacity places ^{1/} heavy dependence on precipitation and run-off for year-round energy supply.

^{1/} As of January 1, 1980, 70% of NWPP capability (including Canada) was hydro-electric. In 1985 hydro is expected to constitute 65% of NWPP capability.

This reliance on uncertain weather conditions, combined with delays in completion of the five WNP units^{1/} (which can provide energy independent of weather conditions) makes energy adequacy uncertain. The West Group of the Northwest Power Pool (which covers Washington, Oregon, part of Idaho and part of Montana) projects ^{2/} a 36% probability of an energy deficiency for its area in 1980-81; the probability of an energy deficiency increases to 95% for 1984-85.

As loads increase and the number of large, dispersed generating units becomes greater, transmission facilities assume a more important role in power supply adequacy and reliability. Adequate transmission is important in providing flexibility of operation in the event of interruptions to fuel supply, drought, large-scale generating unit outages and other situations affecting system operation. Transmission sufficient to move energy in necessary amounts from coal-based areas to oil-based areas can be effective in helping utilities to respond to interruptions to oil supply and in reducing the use of oil even in periods of adequate supply.

The same transmission can help oil-fired areas supply energy to coal-based areas in the event of interruptions in coal supply. It is necessary to maintain a reasonable program of transmission construction in order to assure adequate future reliability of power supply. It is entirely possible that by building additional transmission system facilities, utilities could in selected instances avoid the need to build new generating facilities that would impose financial burdens or create environmental problems. In other instances, overall system reliability could possibly be more cost-effectively enhanced by construction of transmission lines than by the addition of a generating unit. The Reliability Council reports include detailed data on construction of necessary transmission lines.

The ten charts following show graphically the annual net energy; summer peak demands and net capability; and reserve margin at the time of summer peak demand, as projected by each Council (and in the aggregate for the contiguous U.S.) for the years 1980 through 1989. Actual data for 1976 through 1979 are also shown in the charts.

Tables of the capacity, demands, energy requirements and reserves of each Council are provided following the charts, for the years 1976 through 1979 (actual), and 1980 through 1989 (projected).

- ^{1/} Washington Nuclear Project Units 1 through 5, under construction by the Washington Public Power Supply System.
- ^{2/} Pacific Northwest Utilities Conference Committee, "West Group Forecast of Power Loads and Resources, July 1980-June 1991" March 1980. Table 1-1.

I.3 Summary Tables and Graphs

Table 1
 PROJECTED GROWTH OF COUNCIL REGION NET ANNUAL ENERGY REQUIREMENTS 1980-1989
 AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
 TO THE DEPARTMENT OF ENERGY -- APRIL 1, 1980
 CONTIGUOUS UNITED STATES

	<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>1989</u>
<u>Gigawatthours (=1,000 x Megawatthours) *</u>										
ECAR ^{1/}	384,200	406,400	427,600	444,500	461,400	478,900	496,100	513,400	532,000	550,000
MAAC ^{a/}	177,848	184,476	191,391	197,578	204,058	210,729	217,542	223,997	230,362	236,938
MAIN ^{a/}	172,968	176,278	183,273	190,379	196,884	203,995	211,736	219,366	228,121	237,230
MARCA ^{2/}	102,285	107,963	112,274	118,079	124,320	130,016	135,913	142,090	148,265	154,652
NPCC ^{2/}	204,033	206,600	211,105	216,069	221,195	226,194	231,589	237,347	243,175	249,019
SERC ^{a/}	482,619	505,675	531,854	556,035	587,069	610,235	633,203	657,393	683,129	707,347
SWPP ^{a/}	206,182	221,642	233,501	247,145	260,663	274,437	288,701	303,928	319,891	335,879
Subtotal	1,730,135	1,809,034	1,890,998	1,969,785	2,055,589	2,134,506	2,214,784	2,297,521	2,384,943	2,471,065
WSCC ^{2/}	456,210	477,000	497,089	519,279	541,736	566,664	590,100	613,804	638,311	662,217
ERCOT	160,992	170,082	179,349	188,573	198,129	207,937	217,885	227,639	238,644	249,971
U. S. Total	2,347,337	2,456,116	2,567,436	2,677,637	2,795,454	2,909,107	3,022,769	3,138,964	3,261,898	3,383,253

Average % Increase ^{3/}
 1979-1989

	<u>Annual Percent Increase Over Preceding Year</u>										
ECAR ^{1/}	1.37	5.78	5.22	3.95	3.80	3.79	3.59	3.49	3.62	3.38	3.80
MAAC ^{a/}	3.08	3.73	3.75	3.23	3.28	3.27	3.23	2.97	2.84	2.85	3.22
MAIN ^{a/}	1.12	1.91	3.97	3.88	3.42	3.61	3.79	3.60	3.99	3.99	3.33
MARCA ^{2/}	5.98	5.55	3.99	5.17	5.29	4.58	4.54	4.54	4.35	4.31	4.83
NPCC ^{2/}	1.15	1.26	2.18	2.35	2.37	2.26	2.39	2.49	2.46	2.40	2.13
SERC ^{a/}	6.54	4.78	5.18	4.55	5.58	3.95	3.76	3.82	3.91	3.55	4.56
SWPP ^{a/}	7.52	7.50	5.35	5.84	5.47	5.28	5.20	5.27	5.25	5.00	5.77
Subtotal	3.88	4.56	4.53	4.17	4.36	3.84	3.76	3.74	3.81	3.61	4.03
WSCC ^{2/}	7.26	4.56	4.21	4.46	4.32	4.60	4.14	4.02	3.99	3.75	4.53
ERCOT	6.95	5.65	5.45	5.14	5.07	4.95	4.78	4.48	4.83	4.75	5.21
U. S. Total	4.72	4.63	4.53	4.29	4.40	4.07	3.91	3.84	3.92	3.72	4.20

* 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.

a/ Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

1/ Total of Bulk Power and Liaison System Members.

2/ U. S. portion of Council only.

3/ Average of ten annual increases from (1980/1979) to (1989/1988).

Table 2
PROJECTED GROWTH OF COUNCIL REGION SUMMER PEAK DEMANDS 1980-1989
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCIL
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1980
CONTIGUOUS UNITED STATES

	<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>1989</u>
	<u>Megawatts*</u>									
ECAR ^{1/}	64,628	68,176	71,752	74,649	77,404	80,246	83,177	86,056	89,012	92,042
MAAC	33,550	34,550	35,610	36,590	37,600	38,600	39,600	40,550	41,440	42,370
MAIN ^{a/}	34,650	35,973	37,362	38,682	39,956	41,363	42,782	44,301	45,792	47,360
MARCA ^{2/}	19,949	21,275	22,529	23,678	24,911	26,096	27,257	28,417	29,636	30,865
NPCC ^{2/}	35,420	35,820	36,470	37,110	37,780	38,430	39,250	40,150	41,010	41,960
SERC	87,510	91,486	97,103	101,238	106,543	110,712	114,887	119,600	124,297	128,813
SWPP ^{a/}	43,273	45,538	47,952	50,754	53,449	56,253	59,065	62,099	65,257	68,461
Subtotal	318,980	332,818	348,778	362,701	377,633	391,700	406,018	421,173	436,444	451,871
WSCC ^{2/}	77,286	80,600	83,713	87,168	90,710	94,697	98,333	102,086	105,802	109,650
ERCOT	31,621	33,306	35,089	36,873	38,796	40,744	42,735	44,779	46,925	49,161
U.S. Total	427,887	446,724	467,580	486,742	507,189	527,141	547,086	568,038	589,171	610,682

Average % Increase^{3/}
1979-1989 I.
8

	<u>Annual Percent Increase Over Preceding Year</u>									
ECAR ^{1/}	3.93	5.49	5.25	4.04	3.69	3.67	3.65	3.46	3.43	3.40
MAAC	5.57	2.98	3.07	2.75	2.76	2.66	2.59	2.40	2.19	2.24
MAIN ^{a/}	2.51	3.82	3.86	3.53	3.40	3.42	3.43	3.55	3.37	3.42
MARCA ^{2/}	9.84	6.65	5.89	5.10	5.21	4.76	4.45	4.26	4.29	4.15
NPCC ^{2/}	1.95	1.13	1.81	1.75	1.75	1.77	2.13	2.29	2.14	2.32
SERC	5.10	4.54	6.14	4.26	5.26	3.89	3.77	4.10	3.93	3.63
SWPP ^{a/}	14.72	5.23	5.30	5.84	5.31	5.25	5.00	5.14	5.09	4.91
Subtotal	5.74	4.34	4.80	3.99	4.13	3.71	3.66	3.73	3.63	3.53
WSCC ^{2/}	8.93	4.29	3.86	4.13	4.06	4.40	3.84	3.32	3.64	3.64
ERCOT	10.73	5.33	5.35	5.08	5.22	5.02	4.89	4.78	4.79	4.77
U.S. Total	6.66	4.40	4.67	4.10	4.20	3.93	3.78	3.83	3.72	3.65

*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 interregional purchases and sales. The ERCOT demand for 1989 is as reported on line 7 of item 3A.

^{1/} Total of Bulk Power and Liaison System Members.

^{2/} U.S. portion of Council only.

^{3/} Average of 10 annual increases from (1980/1979) to (1989/1988).

a/ Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

TABLE 3
PROJECTED GROWTH OF COUNCIL REGION WINTER PEAK DEMANDS 1980-81 TO 1989-90
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1980
CONTIGUOUS UNITED STATES

	<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>	<u>1989-90</u>
	<u>Megawatts</u> *									
ECAR ^{1/}	66,476	70,390	73,264	76,338	79,414	82,534	85,655	88,704	92,234	95,621
MAAC ^{a/}	29,850	30,980	32,000	33,080	34,230	35,370	36,530	37,560	38,610	39,670
MAIN ^{2/}	28,142	29,293	30,620	31,771	33,061	34,450	35,835	37,337	38,910	40,459
MARCA ^{2/}	18,687	19,636	20,634	21,797	22,887	24,001	25,094	26,226	27,423	28,736
NPCC ^{2/}	35,640	36,440	37,390	38,180	39,020	39,940	40,970	42,060	43,100	44,300
SERC ^{a/}	89,336	94,482	98,644	102,996	108,198	112,418	116,914	121,879	126,677	131,498
SWPP ^{a/}	<u>32,069</u>	<u>33,782</u>	<u>35,702</u>	<u>37,895</u>	<u>40,026</u>	<u>42,235</u>	<u>44,477</u>	<u>46,843</u>	<u>49,342</u>	<u>51,807</u>
Subtotal	300,200	315,003	328,254	342,057	356,836	370,948	385,475	400,609	416,296	432,091
WSCC ^{2/}	76,432	79,745	83,176	86,797	90,648	94,498	98,318	102,094	106,019	107,968
EDOOT	<u>23,456</u>	<u>24,795</u>	<u>26,014</u>	<u>27,386</u>	<u>28,802</u>	<u>30,028</u>	<u>31,827</u>	<u>33,389</u>	<u>35,079</u>	<u>36,881</u>
U. S. Total	400,088	419,543	437,444	456,240	476,286	495,474	515,620	536,092	557,394	576,940
	<u>Annual Percent Increase Over Preceding Year</u>									
ECAR ^{1/}	12.17	5.89	4.08	4.20	4.03	3.93	3.78	3.56	3.98	3.67
MAAC ^{a/}	7.15	3.79	3.29	3.38	3.48	3.33	3.28	2.82	2.80	2.75
MAIN ^{2/}	0.14	4.09	4.53	3.76	4.06	4.20	4.02	4.19	4.21	3.98
MARCA ^{2/}	7.76	5.08	5.08	5.64	5.00	4.87	4.55	4.51	4.56	4.79
NPCC ^{2/}	2.94	2.24	2.61	2.11	2.20	2.36	2.58	2.66	2.47	2.78
SERC ^{a/}	4.46	5.76	4.41	4.41	5.05	3.90	4.00	4.25	3.94	3.81
SWPP ^{a/}	<u>12.90</u>	<u>5.34</u>	<u>5.68</u>	<u>6.14</u>	<u>5.62</u>	<u>5.52</u>	<u>5.31</u>	<u>5.32</u>	<u>5.33</u>	<u>5.00</u>
Subtotal	6.79	4.93	4.21	4.20	4.32	3.95	3.92	3.93	3.92	3.79
WSCC ^{2/}	14.94	4.33	4.30	4.35	4.44	4.25	4.04	3.84	3.84	1.84
EDOOT	<u>6.04</u>	<u>5.71</u>	<u>4.92</u>	<u>5.27</u>	<u>5.17</u>	<u>4.26</u>	<u>5.99</u>	<u>4.91</u>	<u>5.06</u>	<u>5.14</u>
U. S. Total	8.21	4.86	4.27	4.30	4.39	4.03	4.07	3.97	3.97	3.51

* 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. The Council designation is "Peak Hour Demand".

^{a/} Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

^{1/} Total of Bulk Power and Liaison System Members.

^{2/} U. S. portion of Council only.

^{3/} Average of ten annual increases from (1980-81/1979-80) to (1989-90/1988-89).

Table 4
PROJECTED GROWTH OF COUNCIL REGION SUMMER NET DEPENDABLE CAPABILITY 1980-1989
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY -- APRIL 1, 1980
CONTIGUOUS UNITED STATES

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
	Megawatts*									
ECAR ^{1/}	86,113	92,661	94,940	99,413	103,207	107,711	111,274	114,647	119,361	120,552
MAAC ^{4/}	43,099	45,130	46,421	47,533	48,205	50,146	52,347	54,868	55,661	56,546
MAIN ^{2/}	41,993	43,195	44,701	48,388	51,452	52,562	53,059	53,496	54,761	56,456
MARCA ^{2/}	25,645	27,619	28,707	29,449	29,842	31,274	31,593	33,497	34,026	34,726
NPCC ^{2/}	51,187	51,997	52,312	53,551	53,641	55,694	58,035	60,725	60,567	61,340
SERC ^{a/}	114,256	121,817	126,680	130,163	136,985	142,938	146,811	154,553	160,118	164,952
SWPP	52,651	53,616	60,815	63,529	64,137	69,794	71,569	74,564	77,720	80,866
Subtotal	414,944	438,035	454,576	472,626	487,469	510,119	524,688	546,350	562,214	575,438
WSCC ^{2/}	97,676	101,381	108,357	113,541	116,540	121,717	130,484	134,727	138,705	143,137
ERCOT	42,379	44,012	44,327	45,995	46,992	48,486	50,638	52,617	56,523	59,433
U.S. Total	554,999	583,428	607,260	632,162	651,101	680,322	705,810	733,694	757,442	778,058
	Annual Percent Increase Over Preceding Year									
ECAR ^{1/}	(1.31)	7.60	2.46	4.71	3.82	4.36	3.31	3.03	4.11	1.00
MAAC ^{4/}	(4.83)	4.71	2.86	2.40	1.41	4.03	4.39	4.82	1.45	-1.59
MAIN ^{2/}	(5.84)	2.86	3.49	9.37	5.24	2.16	0.95	0.82	2.36	3.10
MARCA ^{2/}	9.27	7.70	3.94	2.58	1.33	4.80	1.02	6.03	1.58	2.06
NPCC ^{2/}	1.20	1.58	0.61	2.55	(0.02)	3.83	4.20	4.64	(0.26)	1.28
SERC ^{a/}	4.05	6.62	3.99	2.75	5.24	4.35	2.71	5.27	3.60	3.02
SWPP	10.56	5.63	9.35	4.46	0.96	8.82	2.54	4.18	4.23	4.05
Subtotal	1.55	5.56	3.78	3.97	3.14	4.65	2.86	4.13	2.90	2.35
WSCC ^{2/}	3.10	3.79	6.88	4.78	2.73	4.35	7.20	3.25	2.95	3.23
ERCOT	2.88	3.85	0.72	3.76	2.17	3.18	4.44	3.91	7.42	5.15
U.S. Total	1.92	5.12	4.08	4.10	3.00	4.49	3.75	3.95	3.24	2.72

AVERAGE % INCREASE^{3/}
1979-1989

I.10

*As reported in Item 3-A, Line 01 of the Council reports. Net dependable capability is the steady hourly output which generating equipment is expected to supply to system load, exclusive of auxiliary power. For the purposes of this table "Net Dependable Capability" includes pumped storage units and other sources which may have energy supply limitations, but which are expected to be available during the peak demand period.

1/ Total of Bulk Power and Liaison System Members.

a/ Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

2/ U.S. portion of Council only.

3/ Average of 10 annual increases from (1980/1979) to (1989/1988).

4/ Staff has modified the data reported by MAAC by assuming that TMI 1 will be out of service in 1980, and TMI 2 will be out of service in 1980 through 1985.

() = negative number

WINTER CAPABILITY

TABLE 5
PROJECTED GROWTH OF COUNCIL REGION WINTER NET DEPENDABLE CAPABILITY 1980-81 TO 1989-90
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1980
CONTIGUOUS UNITED STATES

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90
	Megawatts*									
ECAR ^{1/}	92,679	95,043	99,316	102,309	108,181	111,729	115,415	117,601	122,321	124,540
MAAC ^{5/}	47,103	47,682	48,963	50,094	50,777	52,897	54,984	57,448	58,245	59,110
MAIN ^{2/}	43,850	45,108	49,474	52,008	53,516	53,507	54,004	54,441	56,594	57,949
MARCA ^{3/}	27,322	29,093	29,500	30,712	31,343	32,199	32,362	34,853	35,382	35,582
NPCC ^{3/}	52,969	54,122	54,343	55,533	56,397	58,730	60,880	62,415	62,456	63,783
SERC ^{2/}	120,474	125,385	128,522	135,516	141,012	146,012	149,641	158,586	163,010	168,633
SWPP ^{2/}	53,903	55,669	61,070	63,309	64,918	70,229	71,612	75,534	77,846	81,306
Subtotal	438,300	452,102	471,188	489,481	506,144	525,303	538,898	560,878	575,854	590,903
WSCC ^{3/}	99,628	105,045	109,856	115,563	119,256	125,589	131,705	135,851	140,621	146,091
ERCOT	42,832	43,927	45,455	45,742	48,014	48,688	51,231	55,232	57,918	60,215
U. S. Total	580,760	601,074	626,499	650,786	673,414	699,580	721,834	751,961	774,393	797,209

	Annual Percent Increase Over Preceding Year										Average % Increase ^{4/} 1979-80 to 1989-90
ECAR ^{1/}	4.93	2.55	4.50	3.01	5.74	3.28	3.30	1.89	4.01	1.81	3.50
MAAC ^{5/}	5.54	1.23	2.69	2.31	1.36	4.13	3.95	4.48	1.39	1.49	2.86
MAIN ^{2/}	(2.16)	2.87	9.68	5.12	2.90	(0.02)	0.93	0.81	3.95	2.39	2.65
MARCA ^{3/}	10.80	6.48	1.40	4.11	2.05	2.73	0.51	7.70	1.52	0.57	3.79
NPCC ^{3/}	1.27	2.18	0.41	2.19	1.56	4.14	3.66	2.52	0.07	2.12	2.01
SERC ^{2/}	7.22	4.08	2.50	5.44	4.06	3.55	2.49	5.98	2.75	3.45	4.16
SWPP ^{2/}	11.07	3.28	9.70	3.67	2.54	8.13	1.97	5.48	3.06	4.44	5.34
Subtotal	5.46	3.15	4.23	3.88	3.40	3.79	2.58	4.08	2.67	2.61	3.59
WSCC ^{3/}	1.17	5.44	4.58	5.20	3.20	5.31	4.87	3.15	3.51	3.89	4.03
ERCOT	5.01	2.56	3.48	0.63	4.97	1.40	5.22	7.81	4.86	3.97	3.99
U. S. Total	4.66	3.50	4.23	3.88	3.48	3.89	3.18	4.17	2.98	2.95	3.69

* As reported in Item 3A, Line 01 of the Council reports. Net dependable capability is the steady hourly output which generating equipment is expected to supply to system load, exclusive of auxiliary power.

^{1/} Total of Bulk Power and Liaison System Members.

^{2/} Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

^{3/} U. S. portion of Council only.

^{4/} Average of ten annual increases from (1980-81/1979-80) to (1989-90/1988-89).

^{5/} Staff has modified the data reported by MAAC by assuming that TMI 1 will be out of service for winter 1980-81 and TMI 2 will be out of service for the winters of 1980-81 through 1985-86.

() indicates negative number

RESERVES

Table 6
PROJECTED COUNCIL REGION RESERVE GENERATING CAPABILITY
AS A PERCENTAGE OF PEAK DEMAND, SUMMER AND WINTER
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1980
CONTIGUOUS UNITED STATES

% Reserve Margin At Time Of Summer Peak Demand^{1/}

	<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>1989</u>
ECAR ^{2/}	33.24	35.91	32.32	33.17	33.34	34.23	33.78	33.22	34.10	30.98
MAAC ^{3/}	28.46	30.62	30.36	29.91	28.20	29.91	32.19	35.31	34.32	33.46
MAIN ^{3/}	21.19	20.08	19.64	26.38	28.64	27.07	24.02	20.76	19.59	19.21
MARCA ^{4/}	28.55	29.82	27.42	24.37	19.79	19.84	15.91	17.88	14.81	12.51
NPCC ^{4/}	44.51	45.16	43.44	44.57	42.06	44.92	47.86	51.25	47.69	46.19
SERC ^{3/}	30.56	33.15	30.46	28.57	28.55	29.11	27.79	29.23	28.82	28.06
SWPP ^{3/}	21.67	22.13	26.82	25.17	20.00	24.07	21.17	20.07	19.10	18.12
Subtotal	30.08	31.61	30.33	30.31	29.07	30.23	29.23	29.72	28.82	27.35
WSCC ^{4/}	26.38	25.78	29.44	30.26	28.59	28.53	32.70	31.97	31.10	30.59
ERCOT	34.02	32.14	26.33	24.74	21.13	19.00	18.49	17.50	20.45	20.90
U.S. Total	29.71	30.60	29.87	29.88	28.37	29.06	29.01	29.16	28.56	27.41

% Reserve Margin At Time Of Winter Peak Demand^{1/}

	<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>	<u>1989-90</u>
ECAR ^{2/}	39.42	35.02	35.56	34.02	36.22	35.37	34.74	32.58	32.62	30.24
MAAC ^{3/}	57.80	53.91	53.01	51.43	48.34	49.55	50.52	52.95	50.85	49.00
MAIN ^{3/}	55.82	53.99	61.57	63.70	61.87	55.32	50.70	45.81	45.45	43.23
MARCA ^{4/}	46.21	48.16	42.97	40.90	36.95	34.16	28.96	32.89	29.02	23.82
NPCC ^{4/}	48.62	48.52	45.34	45.45	44.53	47.05	48.60	48.40	44.91	43.98
SERC ^{3/}	34.85	32.71	30.29	31.57	30.33	29.88	27.99	30.12	28.68	28.24
SWPP ^{3/}	68.08	64.79	71.05	67.06	62.19	66.28	61.01	61.25	57.77	56.94
Subtotal	46.00	43.52	43.54	43.10	41.84	41.61	39.80	40.01	38.33	36.75
WSCC ^{4/}	30.35	31.73	32.08	33.14	31.56	32.90	33.96	33.06	32.64	35.31
ERCOT	82.61	77.16	74.73	67.03	66.70	62.14	60.97	65.42	65.11	63.27
U.S. Total	45.16	43.27	43.22	42.64	41.39	41.19	39.99	40.27	38.93	38.18

^{1/} % Reserve Margin = $\left(\frac{\text{Net Dependable Capability}}{\text{Peak Demand}} - 1 \right) \times 100$.

^{2/} Total of Bulk Power and Liaison System Members.

^{3/} Reflects transfer of Associated Electric Cooperative from MAIN to SWPP.

^{4/} U. S. portion of Council only.

Table 7
ACTUAL NET ENERGY, DEMAND, AND CAPABILITY 1976-1979
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS TO THE DEPARTMENT OF ENERGY
CONTIGUOUS UNITED STATES

	Net Annual Energy Requirements (GWH)				Summer Peak Demand (MW)				Summer Net Dependable Capability (MW) ^{1/}			
	1976 ^{1/}	1977	1978	1979	1976	1977	1978	1979	1976	1977	1978	1979
ECAR ^{2/}	338,320	365,526	369,108	379,018	55,219	62,306	62,454	62,182	76,497	79,184	85,730	87,257
MAAC	159,716	164,135	169,766	172,540	29,264	32,306	31,812	31,780	41,358	44,084	43,748	45,285
MAIN ^{3/}	161,769	161,081	168,808	171,052	30,150	33,404	33,222	33,803	38,619	40,830	43,006	44,596
MARCA ^{4/}	78,349	85,738	92,477	96,518	14,938	17,549	18,012	18,162	19,637	20,383	21,941	23,470
NPCC ^{4/}	189,061	194,212	198,918	201,708	32,614	35,448	34,876	34,743	49,272	49,803	49,356	50,582
SERC	419,555	442,233	452,750	452,989	75,116	79,332	80,475	83,260	98,181	101,891	107,447	109,811
SWPP	165,561	179,549	191,550	191,762	33,764	36,514	39,191	37,722	44,115	44,883	46,680	47,622
Subtotal	1,512,331	1,592,474	1,643,377	1,665,587	271,065	296,859	300,042	301,652	367,675	381,058	397,908	408,623
WSCC ^{4/}	382,170	385,887	410,135	425,349	65,503	64,926	68,719	70,948	85,262	87,500	91,487	94,743
ERCOT	120,098	136,413	147,371	150,533	25,330	26,819	28,645	28,556	32,906	35,561	37,759	41,194
U.S. Total	2,014,599	2,114,774	2,200,883	2,241,469	361,898	388,604	397,406	401,156	485,847	504,119	527,154	544,560

	Winter Peak Demand (MW)				Winter Net Dependable Capability (MW) ^{1/}			
	1976-77 ^{1/}	1977-78	1978-79	1979-80	1976-77	1977-78	1978-79	1979-80
ECAR ^{2/}	58,129	59,136	63,450	59,263	79,951	83,793	86,736	88,326
MAAC	27,073	26,723	28,655	27,858	41,405	44,212	44,660	44,631
MAIN ^{3/}	27,123	26,439	28,099	28,102	38,986	41,624	44,060	44,816
MARCA ^{4/}	14,120	15,097	16,631	17,341	20,050	21,227	22,787	24,658
NPCC ^{4/}	34,689	33,767	34,267	34,622	50,993	51,646	52,323	52,306
SERC	79,829	73,861	81,527	85,525	101,838	106,640	110,484	112,358
SWPP	25,286	25,226	28,350	28,404	43,321	45,689	46,786	48,530
Subtotal	266,249	260,249	280,979	281,115	376,544	394,831	407,836	415,625
WSCC ^{4/}	61,985	61,525	70,069	66,495	86,955	87,637	93,529	98,473
ERCOT	18,355	17,950	21,505	22,119	34,501	36,942	39,552	40,788
U.S. Total	346,589	339,724	372,553	369,729	498,000	519,410	540,917	554,886

^{1/} As reported in the FPC Form 12E-2 reports.

^{2/} Total of Bulk Power and Liaison System Members.

^{3/} Includes Associated Electric Cooperative (AEC).

^{4/} U. S. portion of Council only.

AEC transferred from MAIN to SWPP effective June 1, 1980. Projected data for AEC is included in SWPP.

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 1980-1989. For the most part, the data are abstracted from the April 1, 1980 Coordinated Bulk Power Supply Programs (ERA-411) filed with the Department of Energy by the Regional Electric Reliability Councils. 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, although the reliability of those utilities is of importance to the areas they serve.

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. The Division of Power Supply and Reliability does not necessarily endorse all the specific items of information here summarized from the Council reports. The data are presented as reported to the Department of Energy by responsible engineering and management officials of the utility industry, directly concerned with the reliability and economic aspects of bulk power supply planning and operation. Where alternative points of view are supported by documented considerations, the Staff of the Division of Power Supply and Reliability has made appropriate comments. In general, we believe that electric power supply as projected for most regions should be adequate and reliable, given the following assumptions:

- o facilities are completed and placed in operation approximately as scheduled;
- o loads are not significantly greater than those forecast;
- o energy supply for fossil, nuclear and hydroelectric plants is adequate;
- o no unforeseen conditions cause disruption of the normal functioning of the three large national power supply networks. 1/

1/ "Network" as used here includes all facilities for generation, transmission and distribution of electric power.

II.2

In the contiguous United States there are three electric utility power supply 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 Seven-Council Interconnection, which covers all or part of 39 states and 3 Canadian provinces. Of the seven Regional Council areas which comprise this network (ECAR, MAAC, MAIN, MARCA, NPCC, SERC, SWPP), three are interconnected with Canadian systems: ECAR, MARCA, NPCC. All data and discussion in this report refer only to U.S. loads and facilities. Interconnection among utilities in this large area has progressed to the point where capacity and energy in significant amounts can be and is 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. 1/

1/ Studies are underway to examine the costs and benefits of interconnections between ERCOT utilities and utilities in the Southwest Power Pool.

III. ENERGY FORECASTS

The Reliability Council projections of net annual energy requirements,^{1/} extending through 1989, are summarized in Table 1. For the nine individual Council regions, the average annual growth rate for the decade 1979-1989 ranges from the 2.1 percent projected by NPCC to the 5.8 percent estimated by SWPP. Total U.S. electric energy needs are projected to increase at an average annual rate of 4.2 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 made by the Councils, in each year from 1976 through 1980, for the year 1985.

Table III.1
Energy Projections for 1985

<u>Council Projections made in</u>	<u>Total U.S. Net Energy Projected for 1985 (Gwh) (Excludes Alaska & Hawaii)</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
1980	2,909,107	6.08

Ratio of 1980 projection to 1976 projection = 0.8344

^{1/} Net annual energy requirements refers to energy provided by generating plants to the system. It excludes energy used within power plants. It includes transmission and distribution losses, and the net of energy purchases and sales between the United States, Canada and Mexico.

III.2

For the past several years, the near-term annual energy requirements forecast in the Council reports have been higher than the actual energy requirements that finally transpired. Table III.2 is a comparison of the projections made in 1976, 1977, 1978, and 1979 with the actual energy requirements later reported by the Councils for those years.

Table III.2
Comparison of Actual and Projected Energy Requirements
1976-1979
Contiguous United States

<u>Year</u>	<u>Actual</u> ^{1/}	<u>Net Energy Requirements - Gwh x 1000</u>				
		<u>Projected By Councils in Year</u>				
		<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>
1976	2,028	2,031	-	-	-	-
1977	2,115	2,181	2,152	-	-	-
1978	2,201	2,326	2,287	2,245	-	-
1979	2,241	2,469	2,428	2,369	2,322	-
1980	-	2,618	2,579	2,505	2,442	2,347

1/ As reported in the April 1 annual Reliability Council Reports, except for 1976. The 1976 Actual energy is as reported in FPC News Release 23017 dated March 23, 1977, after deduction of Alaska and Hawaii data.

The percentage by which the Council energy projections exceeded the actual energy requirement is shown in Table III.3, which is based on Table III.2.

III.3

Table III.3
Percentage Error in Projection of Energy
1976-1979
Contiguous United States

<u>Year</u>	<u>Percentage Error in Energy Projection*</u>			
	<u>Council Projections Made in Year</u>			
	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
1976	0.15	-	-	-
1977	3.12	1.75	-	-
1978	5.68	3.91	2.00	-
1979	10.17	8.34	5.71	3.61

$$* \left(\frac{\text{Projection for Year "X"} - \text{Actual Energy for Year "X"}}{\text{Actual Energy for Year "X"}} \right) \times 100\% = \% \text{ Error}$$

The evidence of Table III.3 is that:

- (1) Reliability Council projections of net annual energy requirements for the near term have exceeded the actual energy requirements.
- (2) In any one year, the Council projections of net annual energy for future years become increasingly incorrect as the target year becomes further away.
- (3) The Council projections of energy for the year in which the projection is made have become increasingly incorrect from 1976 through 1979.

The aggregate annual increases in net annual electric energy requirements projected by the Councils are shown in the graph of Figure III.1 together with the actual increases experienced since 1969. While the projected increases are well within the range of recorded experience, they appear higher than can now reasonably be expected. The graph of Figure III.1 shows, on the average, a cyclical pattern with each successive peak lower than the preceding one. If this pattern were to continue, the 4.72% increase projected for 1980 over 1979 would approximately follow the trend. There are several factors, however, which indicate this projection is too high:

III.4

- (1) Table III.3 shows that the aggregate of Council projections has been higher than the actual energy requirement in each of the years 1976 through 1979, with an increasing percentage of error.
- (2) Current economic conditions do not appear conducive to a large increase in electric energy use in the near future. 1/
- (3) Continuing and increasing emphasis on conservation will tend to decrease energy use.
- (4) The increased cost of producing electric power, resulting in an increase in the general level of rates, has a negative effect on consumption of electric energy.
- (5) According to the Edison Electric Institute Electric Output Report for the week ended May 31, 1980, net electric energy distributed by the total electric utility industry of the contiguous U.S. for the first 22 weeks of 1980 was 1.2% less than the net electric energy for the corresponding period of 1979.

The foregoing factors lend support to the belief that the increase of the 1980 net energy requirement over the 1979 requirement will be less than the 4.72% projected by the Regional Councils, if indeed there is an increase, and that in subsequent years there will also be smaller annual increases than are projected by the Councils. Therefore, the staff of DPSR has reduced the aggregate of the Regional Council energy projections for the years 1980-1983 as discussed below.

1/ Consideration is being given to large-scale electrification strategies to reduce the use of oil and gas. Such strategies would have a major impact on future growth.

III.5

With the data of Table III.3 and the aggregate Council energy projections as guides, Staff has developed the modified energy projections for 1980 through 1983 shown in Table III.4 below.

Table III.4
Modified Energy Projections For 1980-1983
Contiguous U.S.

Year	Council Gwh x 1000 Projected	Error Factor*	Staff Projection**	
			Gwh x 1000	Annual % Increase
1980	2,347	1.0361	2,265	1.07
1981	2,456	1.0571	2,323	2.56
1982	2,567	1.0834	2,369	1.98
1983	2,678	1.1017	2,431	<u>2.62</u>

AVERAGE = 2.06 ***

* From data in Table III.3

** Modified Projection = Council Projection/Error Factor

*** The average annual increase projected by the Councils for 1980-83 is 4.54%

Table III.5 shows the actual net annual energy requirements of the contiguous U.S. for the years 1968 through 1979; this data was used for plotting Figure III.1. Figure III.1 is a graph of the actual total U.S. annual energy requirements from 1968 through 1979, the energy requirements obtained by aggregating the Council projections through 1985, and the Staff modification of the Council projections through 1983. Staff has not attempted to project energy requirements beyond 1983 in this report. Figure III.2 shows the annual percentage increases of energy requirements corresponding to the graph of Figure III.1.

III.6

Table III.5
Actual Annual Net Energy Growth
1968-1979
Contiguous U.S.

<u>Year</u>	<u>Net Annual Energy</u> <u>Thousands of Cwh*</u>	<u>Annual</u> <u>% Increase</u>
1968	1,327	-
1969	1,440	8.52
1970	1,527	6.04
1971	1,608	5.30
1972	1,741	8.27
1973	1,849	6.20
1974	1,858	0.49
1975	1,910	2.80
1976	2,029	6.23
1977	2,115	4.24
1978	2,197	3.88
1979	2,238	<u>1.87</u>
AVERAGE:		4.89

- * From DOE Reports of total U.S. energy requirements rounded to Gwh after data for Alaska and Hawaii have been removed. This data differs slightly from the energy data reported by the Regional Councils; the differences are not considered significant.

Figure III. 1

Figure III. 2

III.9

The 2.06% average annual growth rate for energy requirements of the contiguous U.S. through the summer of 1983, as obtained in the foregoing discussion, masks the regional variations that are sure to exist. Therefore, the procedure outlined above has been applied to the forecasts made by each of the nine Councils. The resulting projections, which staff considers more probable than those put forward by the Councils, are shown in Table III.6 below. In the same table, in order to provide an appropriate context for the staff estimates, are shown the Council projections averaged for 1980-83, the actual average growth reported for 1976-79 and the actual growth of 1979 over 1978 energy requirements. The staff estimates in Table III.6 are less than the Council projections in all cases, and are less than the actual 1976-79 average growth rate for all Councils except SWPP. The staff estimates are also less than the 1978-79 reported increase for all Councils except ERCOT, SERC and SWPP.

TABLE III.6
Actual and Projected Average Annual Growth Rates
Annual Electric Energy Requirements
For Reliability Council Areas
1976 - 1983

<u>Council</u>	<u>Council</u> <u>Projection</u> <u>1980-1983</u> <u>Average</u>	<u>Actual Growth</u> <u>1976-79</u> <u>Average</u>		<u>Staff Estimate 1/</u> <u>1980-1983</u> <u>Average</u>
ECAR	4.08	3.90	2.68	2.28
ERCOT	5.80	7.91	2.10	3.87
MAAC	3.45	2.61	1.59	1.11
MAIN	2.72	1.90	1.36	0.28
MARCA	5.17	7.23	4.32	3.13
NPCC	1.74	2.18	1.41	(0.20) 2/
SERC	5.26	2.61	0.04	1.02
SWPP	6.55	5.08	0.10	5.71
WSCC	5.12	3.65	3.71	2.67
TOTAL U.S.	4.54	3.63	1.84	2.06

1/ Based on analysis of differences between the annual energy requirements projected by the Councils in the years 1976-1979 for those years, and the actual energy requirements as later reported.

2/ Although the error analysis procedure yields a negative growth rate here, a zero growth rate would not be an unreasonable estimate.

IV. . PEAK DEMAND FORECASTS

The Regional Reliability Council forecasts of peak demand (see Tables 2 and 3) show that each is expected to have a different rate of growth for the next ten years. NPCC projects its summer peak demand to increase at an average annual rate of 1.9% and its winter peak demand to increase at an average rate of 2.5%. These are the lowest growth rates projected by any Council and are lower than the corresponding growth rates projected by NPCC a year ago. At that time, NPCC also projected the smallest growth rate of the nine Council areas. In the current forecast SWPP projects the largest growth rate of the nine Councils, 6.2% for winter and summer peak demands. In 1979 SWPP also projected the largest growth rate of all the Councils: 6.0% for summer and 5.9% for winter. For comparison, the actual summer peak demand for NPCC was 0.4% less in 1979 than in 1978. In SWPP, the 1979 summer peak demand was 3.8% less than in 1978. For the winter of 1979-80, NPCC showed an increase of 1.0% over the peak demand of the preceding winter and SWPP showed an increase of 0.2%. It is to be noted that the current SWPP projection is not comparable to that of the previous year because data for Associated Electric Cooperative, previously reported under MAIN, is now reported, in the tables in this report, under SWPP. The transfer is effective as of June 1, 1980. Although the MAIN and SWPP Long Range Planning Programs, as filed with DOE on April 1, 1980, do not show the effects of the transfer, staff has made the necessary changes in all the tables of this report.

IV.2

Aggregation of the Council demand projections for the summer and winter peak periods results in lesser rates of growth for the total U.S. than were projected last year. The ten-year average annual increase for summer demand is now projected at 4.3%, and for winter at 4.6%. The 1979 projection was 5.2% for summer and 5.4% for winter. The lower growth rates now projected continue a trend that has been evident for the last several years, as shown in Tables IV.1 and IV.2 below:

Table IV.1
Average Annual Increase of Summer Demand
As Projected By The Reliability Councils

Council	Ten-Year Average Annual Percent Increase As Projected April 1 in Year				
	1976	1977	1978	1979	1980
ECAR	<u>1/</u>	<u>5.7</u>	<u>5.2</u>	<u>4.3</u>	<u>4.0</u>
MAAC	<u>1/</u>	<u>4.3</u>	<u>3.8</u>	<u>3.1</u>	<u>2.9</u>
MAIN	<u>1/</u>	<u>5.8</u>	<u>5.2</u>	<u>4.3</u>	<u>3.4</u>
MARCA	<u>1/</u>	<u>6.5</u>	<u>5.7</u>	<u>5.4</u>	<u>5.5</u>
NPCC	<u>1/</u>	<u>4.4</u>	<u>3.5</u>	<u>3.1</u>	<u>1.9</u>
SERC	<u>1/</u>	<u>6.3</u>	<u>6.0</u>	<u>5.4</u>	<u>4.5</u>
SWPP	<u>1/</u>	<u>7.1</u>	<u>6.2</u>	<u>6.1</u>	<u>6.2</u>
Subtotal	<u>6.4</u>	<u>5.8</u>	<u>5.3</u>	<u>4.7</u>	<u>4.1</u>
WSCC	<u>5.6</u>	<u>5.2</u>	<u>4.7</u>	<u>4.4</u>	<u>4.5</u>
ERCOT	<u>6.7</u>	<u>5.7</u>	<u>5.4</u>	<u>5.1</u>	<u>5.6</u>
U.S. Total	<u>6.3</u>	<u>5.7</u>	<u>5.2</u>	<u>4.7</u>	<u>4.3</u>

1/ Not readily available

IV.3

Table IV.2
Average Annual Increase of Winter Demand
As Projected By The Reliability Councils

<u>Council</u>	<u>Ten-Year Average Annual Percent Increase</u> <u>As Projected April 1 In Year</u>				
	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>
ECAR	<u>1/</u>	5.9	5.6	4.8	4.9
MAAC	<u>1/</u>	4.9	4.3	3.6	3.6
MAIN	<u>1/</u>	6.1	5.9	5.0	3.7
MARCA	<u>1/</u>	6.3	6.0	5.8	5.2
NPCC	<u>1/</u>	4.6	3.7	3.6	2.5
SERC	<u>1/</u>	6.4	6.1	5.8	4.4
SWPP	<u>1/</u>	7.1	6.3	5.9	6.2
Subtotal	<u>6.4</u>	<u>6.0</u>	<u>5.5</u>	<u>5.0</u>	<u>4.4</u>
WSCC	5.8	5.3	4.7	4.4	5.0
ERCOT	<u>6.8</u>	<u>5.8</u>	<u>5.4</u>	<u>4.9</u>	<u>5.3</u>
U.S. Total	<u>6.3</u>	<u>5.8</u>	<u>5.4</u>	<u>4.9</u>	<u>4.6</u>

1/ Not readily available

IV.4

As in the case of recent energy forecasts, the aggregate of Council projections of summer peak demand has exceeded the actual value for the last several years. Table IV.3 below compares the actual summer peak demand with the sum of the Council forecasts for the years 1976 through 1979, and Table IV.4 translates the megawatt data of Table IV.3 into percentage of error.

Table IV.3
Comparison of Actual and Projected Summer Demands
1976-1979
Contiguous United States

<u>Year</u>	<u>Peak Summer Demand - Megawatts</u>					
	<u>Actual</u>	<u>Projected by Councils in Year</u>				
		<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>
1976	361,898	379,103	-	-	-	-
1977	388,604	407,413	396,359	-	-	-
1978	397,406	435,577	421,948	412,364	-	-
1979	401,156	463,060	447,693	436,029	426,412	-
1980	-	491,808	475,307	460,077	447,882	427,887

Table IV.4
Percentage Error in Projection of Summer Demand
1976-1979
Contiguous United States

<u>Year</u>	<u>Percentage Error in Demand Projection*</u>			
	<u>Council Projections Made in Year</u>			
	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
1976	4.75	-	-	-
1977	4.84	2.00	-	-
1978	9.61	6.18	3.76	-
1979	15.43	11.60	8.69	6.30

*
$$\frac{(\text{Projection for Year "X"}) - (\text{Actual Demand for Year "X"})}{(\text{Actual Demand for Year "X"})} \times 100\% = \% \text{ Error}$$

IV.5

For winter peak demand, the aggregate of Council projections also differs from the actual value for the contiguous U.S., as shown in Tables IV.5 and IV.6.

Table IV.5
Comparison of Actual and Projected Winter Demands
1976-1979
Contiguous United States

<u>Year</u>	<u>Peak Winter Demand - Megawatts</u>					
	<u>Actual</u>	<u>Projected by Councils in Year</u>				
		<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>
1976-77	346,589	343,427	-	-	-	-
1977-78	339,724	367,355	360,447	-	-	-
1978-79	372,553	391,931	383,688	380,541	-	-
1979-80	369,729	416,630	408,154	401,942	394,796	-
1980-81	-	442,419	433,614	425,582	416,191	400,088

Table IV.6
Percentage Error in Projection of Winter Demand
1976-1979
Contiguous United States

<u>Year</u>	<u>Percentage Error in Projection of Winter Demand*</u>			
	<u>Council Projections Made in Year</u>			
	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
1976-77	(0.91)	-	-	-
1977-78	8.13	6.10	-	-
1978-79	5.20	2.99	2.14	-
1979-80	12.69	10.39	8.71	6.78

*($\frac{\text{Projection for Year "X"}}{\text{Actual Demand for Year "X"}} - 1 \times 100\% = \% \text{ Error}$)

IV.6

A well-known difficulty in the projection of peak demand, winter or summer, is the effect of temperature. Careful construction of a comprehensive model for demand, with thorough research into the historic magnitudes of the various parameters and detailed consideration of possible changes in the relevant factors, may give an accurate forecast for normal weather conditions. But unusual weather conditions may affect the demand so greatly that the forecast of a single number for peak demand will be greatly in error. An unusually cold period of only several days, in some areas, will be sufficient to create an exceptionally high winter peak. An unusual warm period of only a few days can in some areas raise the summer peak demand to a level much higher than normal. The effect in summer would be increased by high humidity and lack of wind. Short periods of unusual weather have a greater effect on peak demands than on annual energy requirements. Therefore, in the reporting of demand forecasts, a range of values would be more suitable than a single number. The range of summer peak demand could be given in terms of a cool, normal or hot summer. The range of winter peak demand could be given for a warm, normal or cold winter. The effect of weather on generator output is discussed in Section V.

Further analysis of Tables 2 and 3 shows that five Councils firmly expect to remain as summer peaking areas (summer peak greater than the following winter peak); these are MAAC, MAIN, MARCA, SWPP and ERCOT. In the MAAC region, however, the winter peak increases gradually from 89% of the summer peak in 1980 to 94% in 1989. Three regions (ECAR, SERC and NPCC) are winter-peaking and project they will remain so. NPCC, in fact projects increasing dominance of the winter peak, from 100.6% of the summer peak in 1980 to 105.6% in 1989. The WSCC area projects winter and summer peak demands to be nearly equal, with the winter peak fluctuating between 98% and 100% of the summer peak during the entire 1980-1989 period. The U.S. as a whole is expected to remain summer-peaking. Table IV.7 shows the data relating winter peak demand to summer peak demand.

Table IV.7
Ratio of Projected Winter Peaks to Summer Peaks
Based on Reliability Council Projections of April 1, 1980

Ratio Winter Peak/Summer Peak										
	<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>	<u>1989-90</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>1989</u>
ECAR	1.029	1.032	1.021	1.023	1.026	1.029	1.030	1.031	1.036	1.039
MAAC	0.89	0.90	0.90	0.90	0.91	0.92	0.92	0.93	0.93	0.94
MAIN	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84	0.85	0.85
MARCA	0.94	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.93	0.93
NPCC	1.006	1.017	1.025	1.029	1.033	1.039	1.044	1.048	1.051	1.056
SERC	1.021	1.033	1.016	1.017	1.015	1.015	1.018	1.019	1.019	1.021
SWPP	0.74	0.74	0.74	0.75	0.75	0.75	0.75	0.75	0.76	0.76
Subtotal	0.94	0.95	0.94	0.94	0.94	0.95	0.95	0.95	0.95	0.96
WSCC	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	0.98
ERCOT	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.76	0.75	0.75
U.S. Total	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94

IV.8

Because of the magnitude of the previous differences between actual and forecasted values (shown in Tables IV.3, IV.4, IV.5 and IV.6), staff has adjusted the summer peak demand forecasts downward to more accurately reflect what appears to be a continuing trend toward lower load growth rates. On the assumption that load factor for the contiguous U.S. will remain substantially constant through 1983, staff has used its projected percentage annual increase in energy requirements (derived in Section III), to obtain summer peak demand projections through 1983; these are shown in Table IV.8 as the "Low" Staff estimate.

In order to obtain a range of annual increase, instead of a single number, the period following the 1973 "oil embargo" was selected for study. In the period 1973-1977 the annual increase in summer peak demand averaged 2.94%. Staff has used this percentage increase to obtain the "High" Staff estimate in Table IV.8. Table IV.8 data has been used to plot Figure IV.1. The figure also shows the Council projections through 1985 and the actual reported peaks for the years 1968 through 1979.

Table IV.8
Range of Summer Peak Demand Projections
For Contiguous U.S., 1980-1983

<u>Year</u>	<u>Council</u>		<u>Staff Estimates</u>			
	<u>Projections</u>		<u>Low</u>		<u>High</u>	
	<u>MW</u>	<u>% Increase</u>	<u>MW</u>	<u>% Increase</u>	<u>MW</u>	<u>% Increase</u>
1979	401,156	-	-	-	-	-
1980	427,887	6.66	405,448	1.07	412,950	2.94
1981	446,724	4.40	415,827	2.56	425,091	2.94
1982	467,580	4.67	424,060	1.98	437,589	2.94
1983	486,742	4.10	435,170	2.62	450,454	2.94
AVERAGE:		4.96		2.06		2.94

Figure IV. 1

V. Generating Capacity

According to the Council reports, total net dependable generating capacity in the United States will increase from a reported 544,560 MW in summer 1979 to a projected 778,058 MW in summer 1989. This increase is the net of additions to capacity in the form of new units and upratings^{1/} and subtractions from capacity caused by retirements and deratings.^{2/} The magnitude of the net increase (778,058 - 544,560 = 233,498) indicates the average annual completion of approximately 23,350 MW of generating capacity. For purposes of comparison, the average annual increase of capacity for the past several years is tabulated below:

Table V.1

Net Dependable Generating Capability
At Time of Summer Peak
Contiguous U.S.

<u>Year</u>	<u>Capability</u> <u>(MW)</u>	<u>Annual Increase</u> <u>(MW)</u>
1976	485,847	-
1977	506,193	20,346
1978	530,902	24,709
1979	544,560	13,658

^{1/} An existing unit may have its rated capacity increased due to re-evaluation of its ability to produce power, changes in the structure and operation of some of its components, a change to higher-quality fuel, or other reasons.

^{2/} An existing unit may have its rated capacity decreased due to re-evaluation of its ability to produce power, installation of more effective air pollution controls, a change to lower-quality fuel, conversion from oil to coal, or other reasons.

SERC projects the largest increase of all the Councils and WSCC projects the next largest increase, as shown in Table V.2. The smallest increase in capacity for the 1979-89 period is that projected by NPCC, which also projects the smallest increase in growth of energy requirements and peak demand. Although in terms of 1979 annual energy requirements, MAAC was nearly 79% larger than MARCA, and MAAC's summer demand exceeded that of MARCA by almost 75%, MARCA and MAAC project practically the same magnitude of net capability increase between 1979 and 1989. This may be due to MARCA's having a larger projected rate of growth than MAAC.

Table V.2

Capacity Increases Projected by Councils
Summer 1979 to Summer 1989

<u>Council</u>	<u>Capability in Megawatts</u>		<u>Total</u> <u>Increase</u>	<u>Average Annual</u> <u>Increase</u>
	<u>Summer</u> <u>1989</u>	<u>1979</u>		
ECAR	120,552	87,257	33,295	3,330
MAAC	56,546	45,285	11,261	1,126
MAIN ^{1/}	56,456	42,769	13,687	1,369
MARCA	34,726	23,470	11,256	1,126
NPCC	61,340	50,582	10,758	1,076
SERC	164,952	109,811	55,141	5,514
SWPP ^{1/}	80,866	49,449	31,417	3,141
Sub Total	575,438	408,623	166,815	16,682
WSCC	143,187	99,743	48,444	4,844
ERCOT	59,433	41,194	18,239	1,824
U.S. Total	778,058	544,560	233,498	23,350

^{1/} Adjusted to reflect transfer of Associated Electric Cooperative from MAIN to SWPP effective June 1, 1980. The 1979 capability has also been adjusted to reflect this transfer for the purposes of this table.

V.3

Most of the total increase in U.S. generating capacity is projected to be nuclear and coal-fired, although not all areas project the same percentages of these units. MARCA, for instance, projects no new nuclear units for the entire period 1980-89, ECAR projects about 26% of its capacity changes to be new nuclear units and MAAC has scheduled some 72% of its projected capacity changes to be new nuclear units. MAAC has also scheduled the retirement and derating of existing capacity at about 17% of the total changes. ECAR's retirement and derating program amounts to barely 1% of its total capacity changes for 1980-1989. Table V.3 shows the Council-by-Council capacity changes by percentage, for a selected group of Councils.

Table V.3

Projected Capacity Changes 1980-1989
By Type of Unit
(4 Councils Only)

<u>Council</u>	<u>Approximate Percentage by Type</u>							<u>Total</u>
	<u>Nuclear</u>	<u>Fossil</u>	<u>Hydro</u>	<u>P.S.</u>	<u>GT/IC</u>	<u>Other</u>	<u>U,D,R 1/</u>	
ECAR	26.2	70.1	0.2	3.3	1.1	0	(0.9)	100
MAAC	72.4	42.6	1.8	0	0.1	0	(17.0)	100
MARCA	0	103.8	0.7	0	0	0	(4.5)	100
SWPP	23.2	82.8	0.1	0.6	1.0	1.4	(9.0)	100

1/ U.D,R = Net of updatings, deratings, retirements.

VI. Reserve Margins

The installed reserve (planned reserve) margins for each Council area and the contiguous U.S. are shown in Table 6 for the summer and winter peak load periods from 1980 through 1989. Inter-regional transfers of capacity, 1/ and transfers within a region between Council members and non-members, are excluded from the reserve margins of Table 6. At the time of peak demand the actual margin available will be affected by capacity reductions due to maintenance and forced outages of generating and transmission facilities, by lower-than-normal fuel quality, operating problems and other factors. For the entire period, the margins are large enough in all Councils but MARCA to indicate that bulk power supply should be reasonably reliable, under normal conditions. MARCA's summer reserve is low from 1986 on. Electric Region margins are reviewed in Section XI.

The margins were computed on the basis of the peak demands and generating unit construction schedules projected by the Councils. Deviations from the projections will affect the margins. To the extent that peak demands are less than those projected by the Councils, margins will be improved. 2/ If the average annual increase of summer peak demand is close to the range projected by staff, 3/ margins will certainly improve if the projected construction schedules are met. However, to the extent that generating units and transmission lines are delayed, and construction schedules are not adhered to, margins will be decreased. The margin at the time of peak demand, as can be seen, will be affected by the two factors: annual rate of load growth and completion of projected units. The various probability measures used to relate margin to reliability indicate that reliability is more sensitive to a decrease in margin than it is to an increase.

1/ See Section IX and Table IX.1

2/ An increase in installed reserve margin does not of itself guarantee an increase in bulk power supply reliability, although it is probable that reliability would increase.

3/ See Section IV of this report.

VI.2

For example, at a 15 percent reserve margin, ^{1/} a decrease of 2% in the reserve margin would reduce the reliability level more than a 2% increase in margin would increase the reliability level. This effect supports the argument that generating unit construction should not be slackened too hastily in anticipation of a large decline in demand, if reliability is to be maintained. Because resumption of suspended construction is not always easy, and is likely to lag behind sudden increases in demand, reserve margins should be planned more to the higher values than to the lower values. Since nuclear plants are the center of much controversy currently, it is pertinent to show how national reserve margins would be affected if no new nuclear units were to be licensed. Tables VII.3 and VII.4 show, for 1985 and 1989, the summer reserve margins for the U.S., with and without operation of nuclear units as currently scheduled.

^{1/} An installed (planned) reserve margin in the range of 15% to 25% of annual peak demand has historically been considered sufficient for reliable service.

VII. NUCLEAR CAPACITY1. General Overview

New nuclear units are projected to constitute a large portion of the planned net increase in total U.S. capability between 1979 and 1989. Eighty-six nuclear units now under construction or planned for construction, totalling 93,619 MW (summer net capability), are listed by the Councils, with initial commercial operating dates between January 1, 1980 and December 31, 1989. This capacity amounts to 40.09% of the total net increase in generating capability in that period. Table VII.1 below shows the capacity of new nuclear units projected by each Council and the fraction of total capacity increase represented by these units.

Table VII.1
Projected Nuclear Capacity
Reported By Each Reliability Council
For 1980-1989

Council	<u>New Nuclear Capacity</u>		<u>Total Net 1/ Capacity Increase (Summer)</u>	<u>New Nuclear MW As Percent of Total Incr.</u>
	<u>No. of Units</u>	<u>MW (Summer)</u>		
ECAR	10	8,871	33,295	26.64
MAAC	8 ^{2/}	8,577	11,261	76.17
MAIN	9	9,764	11,860	82.33
MARCA	-0-	-0-	11,256	-0-
NPCC	6	6,500	10,758	60.42
SERC	28	30,675	55,151	55.63
SWPP	7	7,762	33,244	23.35
Subtotal	68	72,149	166,815	43.25
WSCC	13	15,540	48,444	32.08
ERCOT	5	5,930	18,239	32.51
U.S. Total	86	93,619	233,498	40.09

1/ Net of new units added, upratings, deratings and retirements.

2/ Excluding Three Mile Island Units 1 and 2.

VII.2

It is evident that the Regional Councils differ greatly in the proportion of nuclear capacity which is planned in relation to the total capacity increase. MARCA projects no new nuclear units at all, while SERC projects 28. Although SERC projects by far the largest increment of new nuclear generating capacity, this will constitute only 55.6% of SERC's total capacity increase. MAIN is the Council which projects that nuclear capacity will make up the largest portion (82.3%) of its net capacity increase.

The implication of Table VII.1 with respect to reserve margins is that delays in completion and licensing of nuclear units will have different effects on the nine Regional Councils. 1/ In MARCA there will be no direct effect, discounting the possibility that MARCA may need capacity support from other Council areas in which nuclear capacity reliance is heavy. In MAAC and MAIN it appears that the impact on reserves would be greatest. In NPCC the effect would certainly be significant, as it would be in SERC. What is not shown in Table VII.1 is the distribution of proposed new nuclear units among the subregions of the Council areas. TVA, for instance, one of the four sub-regions of SERC, projects that all of its new capacity in the period 1980-1989 will be nuclear. Therefore, delay of nuclear licensing would indeed penalize the TVA region heavily. Table VII.2 shows the sub-regional (Electric Region) distribution of the projected new nuclear capacity.

1/ If the delay in issuance of nuclear operating licenses continues, installed reserves will be critically low in nine electric Regions. The most heavily impacted areas in the near term (1980-1982) are the Northwest Power Pool, the Northern California-Nevada Electric Region and the Commonwealth Edison Co. A detailed discussion of the Electric Regions is contained in part 2 of this section and in Section XI.

Table VII.2
New Nuclear Capacity
Projected For Each Electric Region 1/
1980-1989

<u>Council & Region</u>	<u>New Nuclear Capacity</u>	
	<u>No. of Units</u>	<u>MW (Summer)</u>
<u>ECAR</u>		
1. APS	0	0
2. AEP	0	0
13. CAPCO	3	3,178
14. CCD	1	792
15. Kentucky	0	0
16. Indiana	3	2,520
18. MECS	3	2,381
<u>MAAC</u>		
5. PJM	8	8,577
<u>MAIN</u>		
v. CECO	6	6,516
17. ILLMO	3	3,248
19. WUMS	0	0
<u>MARCA</u>		
20. MAPP	0	0
<u>NPCC</u>		
3. NEPOOL	4	4,600
4. NYPP	2	1,900

1/ See Map for locations of Electric Regions.

Table VII.2 (Continued)
New Nuclear Capacity
Projected For Each Electric Region
1980-1989

<u>Council & Region</u>	<u>New Nuclear Capacity</u>	
	<u>No. of Units</u>	<u>MW (Summer)</u>
<u>SERC</u>		
7. Florida	1	795
9. Southern	3	3,107
11. TVA	13	15,811
12. VACAR	11	10,962
<u>SWPP</u>		
8. MSU	4	4,522
10. Gulf	1	940
21. MOKAN	1	1,150
22. Oklahoma	1	1,150
<u>WSCC</u>		
24. RMPP	0	0
25. NWPP (Part)	6	7,340
26. Az-Nm	3	3,810
27. So Cal-N	2	2,200
28. No Cal-N	2	2,190
30. Id-Ut (Balance of NWPP)	0	0
<u>ERCOT</u>		
23. TIS	5	5,930

No exact knowledge of how a delay of nuclear licensing would affect system reliability can be gained from mere tabulation of the nuclear capacity under consideration. Only a preliminary indication is obtainable, through examination of the reserve margins. Table VII.2 shows that projected nuclear units are scattered among the councils and Electric Regions in a random pattern.

Reliability analysis of the effect on a region of a long-term nuclear licensing delay would require review of projected loads (peak demands and energy), existing capacity and projected capacity other than nuclear within the region and within adjoining regions, and the transmission system. Here we have provided only a preliminary indication of reliability problems by showing the effect on reserve margins of delays in commercial operation of nuclear units. Estimates of the inter-regional transfers which could increase reliability are discussed in Section IX. A major difficulty in this analysis stems from the uncertainty associated with the projected commercial operating dates of the nuclear units, since lack of projected nuclear units might cause cancellation of some inter-regional power transfers. Several of the dates given in the Council reports (for Marble Hill Units 1 and 2, for instance) are unrealistic in the view of Staff, but information on more realistic dates is unavailable. In order to bound the problem, two estimates have been made, as described below.

One estimating procedure is to assume that none of the nuclear units projected for 1980-89 will achieve commercial operation in that period, and to compute the resulting reserve margins. This may appear to be an extreme view of the situation, but it does provide a maximum boundary for delineating the effect of projected nuclear capacity curtailments. To indicate the magnitude of this effect, two target years have been chosen, 1985 and 1989. Table VII.3 shows the Council reserve margins in summer 1985 with and without all the nuclear units.

VII.6

Table VII.3
Effect of Projected Nuclear Capacity
on Summer 1985 Reserve Margins

<u>Council</u>	<u>Projected Reserve Margin, Percent</u>	
	<u>With New Nuclear Units 1/</u>	<u>Without New Nuclear Units</u>
ECAR	34.23	26.46
MAAC	29.91	16.09
MAIN	27.07	6.25
MARCA	19.84	19.84
NPCC	44.92	36.80
SERC	29.11	13.59
SWPP	24.07	12.32
Subtotal	30.23	18.21
WSCC	28.53	16.10
ERCOT	19.00	10.29
U.S. Total	29.06	17.22

1/ As projected through June 1985 by the Reliability Councils, April 1, 1980, but with Three Mile Island Unit 2 excluded by Staff.

Table VII.4
Effect of Projected Nuclear Capacity
on Summer 1989 Reserve Margins

<u>Council</u>	<u>Projected Reserve Margin, Percent</u>	
	<u>With New Nuclear Units 1/</u>	<u>Without New Nuclear Units</u>
ECAR	30.98	21.34
MAAC	33.46	13.21
MAIN	19.21	(1.41)
MARCA	12.51	12.51
NPCC	46.19	30.70
SERC	28.06	5.20
SWPP	18.12	6.78
Subtotal	27.35	11.65
WSCC	30.59	16.41
ERCOT	20.90	8.83
U.S. Total	27.41	12.28

() = Negative number

1/ As projected through June 1989 by the Reliability Councils, April 1, 1980, but with Three Mile Island Unit 2 excluded by Staff.

VII.7

Inspection of Table VII.3 shows that if no new nuclear units were to be added in the period 1980-1985, MAIN and ERCOT would have reserve margins below 12% and SWPP would be barely above that level; ^{1/} it could be expected that these Council areas would have less than satisfactory reliability. If no new nuclear units are added from 1980 through 1989, Table VII.4 shows, MAIN's reserve would actually be negative in 1989 and SERC, SWPP and ERCOT would have margins below 12%. MARCA projects a low margin, even without nuclear problems. All these low margins are of course predicated on the assumption that the summer peak demands would occur as projected by the Councils.

A second procedure for estimating reserves has been applied only to 1985. Staff has reviewed the latest data available, concerning nuclear construction and licensing as of early May 1980, and has established possible commercial operating dates different from those reported by the Councils in their April 1, 1980 reports. On the basis of these dates, Staff has computed Council area reserve margins that differ from those projected by the Councils. The Council projections and the Staff estimates of new nuclear capacity in commercial operation year by year through June 1985 are compared in Table VII.5. The summer 1985 reserve margin for the total U.S., with the staff-estimated nuclear units in place, is estimated to be 28.23%. Part 2 of this Section discusses in detail the specific nuclear units projected and how lack of operating licenses for them will affect the various Electric Regions.

^{1/} An installed (planned) reserve margin of 15% has historically been regarded as minimal, for a reasonable level of reliability. For the purposes of this report, Staff has used 12% as the minimum acceptable. Below the 12% level, in Staff opinion, many systems could not maintain consistently reliable service on a long-term basis.

Table VII.5
New Nuclear Capacity Projections
1980-1985

<u>Year</u>	<u>Completion of New Nuclear Capacity</u>			
	<u>Council Projections 1/</u>		<u>Staff Estimate 2/</u>	
	<u>MW</u>	<u>No. of Units</u>	<u>MW</u>	<u>No. of Units</u>
1980	8,008	8	3,935	4
1981	10,525	10	9,381	9
1982	12,116	11	10,078	9
1983	12,383	11	14,153	13
1984	11,953	11	10,841	10
1985	11,421	7	8,790	8
Total	62,406	58	57,178	53

A detailed analysis of the effect of nuclear units on regional reserves is given in Section VII part 2.

1/ As projected in the April 1, 1980 Council Reports.

2/ As estimated by Division of Power Supply and Reliability on the basis of information available as of early May 1980. Includes Three Mile Island No. 1 as of January 1, 1981; excludes Three Mile Island No. 2 for the period 1980-1985.

2. Detailed Regional Analysis - Impact of Delays in the Issuance of Nuclear Operating Licenses Through 1985.

An analysis was conducted to determine the regional power supply outlook, assuming the delay in issuing nuclear operating licenses continues through 1985. The load and capacity data used was reported by the Regional Electric Reliability Councils to the Department of Energy, April 1, 1980, for the contiguous U.S.. This data was updated, in some instances, to reflect new generating capacity schedule changes that occurred after the April 1, 1980 date. Greater detail on the methods used in this analysis will be given at the end of this section. The results of the analysis are as follows:

Impact on Energy Supply:

Table VII-2-1 shows the "lost" nuclear generation by electric region for the years 1980-1985. By 1985 the lost generation is nearly 10% of the total electric energy requirement for the contiguous U.S. This energy requirement must be made up by some combination of coal, oil, and gas generation. The approximate allocation of fossil energy to replace this generation is shown in Table VII-2-2. These percentages take into account both the relative amounts of coal, oil, and gas generation in a particular region, and also the existing capacity factors of each type of generation. These two factors together determine the relative ability of a particular type of generation to pick up additional energy.

Table VII-2-3 indicates the areas that will most likely not be able to completely make up the loss of planned nuclear generation, even with imports from other regions and therefore, be in a position to suffer an energy supply shortfall. These areas are the Gulf States Utilities Group (1984-1985), the Texas Interconnected Systems Group (1984-1985), and the Northern California-Nevada Group (1985).

The Northwest Power Pool (East and West group combined) will likely have an energy supply shortage even if the nuclear units are built as planned. Better than "adverse" hydro conditions may alleviate some of the energy shortage, but the loss of some 2300 MW by 1985 will greatly aggravate the energy supply situation in the Pacific Northwest.

Impact on Reserve Margins:

As shown in Table VII-2-4 total reserve margins will be critically low in nine electric regions by 1985, if the delay in the issuance of operating licenses continues. The worst areas the Northern California-Nevada Group, and the Commonwealth Edison Co. A region was designated as having "critically low" reserves if the summer or winter total reserve margin, (adjusted for net transfers), was below 12%. ^{1/} These figures reflect inter-regional transfers to areas having energy shortages.

The Northwest Power Pool Group has critically low winter reserve margins in the 1980-82 timeframe even though no nuclear units are planned in this period. The loss of WNP # 1 & WNP #2 ^{2/} in the 1983-85 timeframe further aggravates an already tight capacity situation in the Pacific Northwest.

Impact on Additional Fossil Fuel Use:

The "lost" nuclear generation shown in Table VII-2-1 must be made up by some combination of increased coal, oil, and gas generation. Tables VII-2-5, 6, and 7 list the estimated increased coal, oil, and gas use, respectively, which would be required to make up this "lost" nuclear energy. These tables include the impacts of interregional transfers, to the extent possible, in an attempt to relieve areas with supply shortages.

Coal

The areas having the largest increases in coal use are the Virginia-Carolinas Group, the Tennessee Valley Authority Group, and the Commonwealth Edison Co. These three areas above will use nearly 47% of all the additional coal use through 1985, as shown in Table VII-2-5. By 1985 the total coal use would increase by approximately 151,000 tons/day, which represents an increase in total utility coal use of over 7%.

^{1/} A total reserve margin of 12 percent was considered by ERA staff to be the minimum reserve required to cover such events as unit deratings, forced outages, and spinning reserve requirements for most systems. Normally, utilities plan for higher total reserve margins than this to allow for unexpected events, such as extremely hot weather.

^{2/} WNP = Washington Nuclear Plant

Oil

The areas with the largest increases in oil use in the 1980-1985 time frame are the Pennsylvania-New Jersey-Maryland Interconnection, the Northern California-Nevada Group, the Commonwealth Edison Co., and the Southern California-Nevada Group. These four areas will use over 60% of the total increased oil use shown in Table VII-2-6. By 1985 the total utility oil use would increase by approximately 697,000 barrels/day, which represents an increased utility oil use of over 33%.

Gas

By 1985 Gas use will increase by 932,000 mcf/day, which is a 22% increase over MERC's projections. Almost all (90%) of the increased gas use in the 1980-85 time frame will occur in two regions; the Middle South Utilities Group and the Texas Interconnected Systems Group.

Nuclear Unit Licensing Priorities:

Table VII-2-8 lists the nuclear units that would be affected by a continued delay in issuing operating licenses.

These units were placed on a priority list according to the following criteria:

- (1) Unit is necessary to relieve energy shortfall (Table VII 2-3).
- (2) Unit is necessary to relieve low reserve situation (Table VII-2-4).
- (3) Unit is located in oil dependent Region (Table II-2-6) Table VII-2-9 shows a priority list of nuclear unit for the 1980-85 time frame. These units were prioritized using a combination of the three above mentioned criteria. Units needed to relieve an energy supply shortfall or low reserve margin situation were generally given a higher weight than units needed primarily to reduce oil consumption.

Impacts of Lower Than Forecasted Growth Rates on Energy Shortages, Reserve Margins and Fuel Use:

A sensitivity analysis was performed for those regions having either energy supply or reserve major problems to determine the extent to which lower growth rates might alleviate these problems. It was assumed that the schedule of capacity additions would remain unchanged.

Table VII-2-10 compares the 1980-95 growth rates projected by the reliability councils with the lower growth rates projected by ERA staff for the purposes of this sensitivity analysis.

The lower growth rates were chosen by examining the historical forecasting errors made by each of the nine reliability councils, and scaling down their current forecasts accordingly. See Section III and IV for a further description of this method. The exceptions to this method were TVA and VACAR where a "lower limit" growth rate of 1.0% was used.

Impact of Lower Growth Rates on Energy Supply

The original analysis projected three areas as having energy shortage in the 1980-85 timeframe (see Table VII-2-3). Using lower growth rates than those projected by the reliability councils, no energy shortage problems would be anticipated.

Impact of Lower Growth Rate on Reserve Margins

Table VII-2-4 lists nine areas having reserves below 12% under the original growth assumptions. Using lower growth rates reduces the number of critical areas to three as shown on Table VII-2-11. Those areas are the Commonwealth Edison Co., the Middle South Utilities Group, and the Northern California-Nevada Group.

Impact of Lower Growth Rates on Fuel Use

Tables VII-2-5, VII-2-6, and VII-2-7 lists the additional coal, oil, and gas use that would result, under the original growth rates, if the nuclear units do not come on line as planned. These same increases in coal, oil and gas use would occur, even with reduced growth rates, because nuclear units are operated in base load. Delays in bringing these units on line would necessitate some other type of base load generation taking its place resulting in the increased fossil fuel use shown.

These increases in fossil fuel use are due to the nuclear units not coming on line as planned. If energy growth rates are lower than those projected by the reliability councils, there would be a partially offsetting reduction in fossil use due to the lower system energy requirements. The total energy requirement for the contiguous U.S., as reported by the reliability councils, is projected to increase from 2,421,676 GWH in 1980 to 3,072,369 GWH in 1985. This represents a compound annual growth rate of 4.87%. If the compound annual growth rate of 2.06%, the reduction in the energy requirement in 1985 would be 390,770 GWH. Allocating this reduction in generation over available coal, oil, and gas units would result in the following approximate decreases in fossil fuel use: Coal 316,300 tons/day; oil - 460,400 BBL/day; and Gas - 976,400 MCF/day.

This reduction in coal would more than offset the coal increases shown in Table VII-2-5. Similarly, the reduction in gas use would effectively cancel out the increases shown in Table VII-2-7.

The situation for oil is different. Combining the increases in oil use due to licensing delays in 1985 (697,400 BBL/day) and the decrease in oil use if lower growth occurs (460,400 BBL/day) results in a net increase in oil use of 237,000 BBL/day.

Methodology:

The immediate impact of further delays in issuing nuclear unit licenses would be a reduction in the future amount of nuclear energy generated by the electric utility industry. Since customer energy requirements must still be supplied, this will produce a corresponding increase in fossil-fueled generation

and fossil fuel consumption. The underlying assumption in this report is that all energy that would have been produced by nuclear generation if there were no licensing delays would now need to be made up by some combination of additional coal, oil and gas fired generation.

Calculation of Unprovided Nuclear Energy

The first task was to calculate the amount of nuclear energy that would be "lost" because of continued licensing delays. The projected commercial in-service dates for all nuclear units due to come on-line between January 1980 and December 1985 were extracted from the April 1980 submissions of the Form ERA-411. This information was supplemented with telephone calls to the appropriate utilities and with information received from the NRC. The amount of energy these units would have produced was calculated as:

- (1) UNIT SUMMER CAPACITY IN MW X PERIOD HOURS X
ANNUAL CAPACITY FACTOR.

The annual capacity factor $\frac{1}{2}$ for these units was developed by examining the historical performance of existing nuclear units 700 MW and larger from 1974 to 1979. The results of these studies showed that the average annual capacity factor for all units considered was approximately 57% for the in-service year and the first full calendar year of operation after the in-service year. A 64% capacity factor was considered representative for all subsequent years of operation.

Period hours (the number of hours to be considered) for the first year of operation was calculated from the first day of the month of commercial operation to the last day of that calendar year. The capacity used was the summer capacity as reported in the Reliability Council Reports.

1/ Capacity Factor is the ratio of energy actually generated in a period to the product of hours in the period and rated capacity of the unit.

Calculation of Additional Fossil Generation

As stated above it was assumed that a MWH of nuclear energy not generated would be replaced by some combination of coal, oil and gas generation. A rigorous method for determining how much more of each of these fuels would be used is to perform a production cost study for each of the many operating groups affected by the delay in licensing a nuclear unit. However, the time constraints imposed on the study would not allow such an ambitious undertaking, and it is possible that such precision would not yield more credible results. Therefore, an alternate technique was developed.

It was assumed that the probability of a particular type of fossil capacity (coal, oil, gas) picking up additional load would be proportional to the amount of that type of capacity in a region. However, if that type of generating capacity was already operating at a very high capacity factor, other constraints such as load profile, forced outages and maintenance would prevent substantial increases in its output. Based on these considerations, the following formula was developed to calculate the amount of the "lost" nuclear energy that would be picked-up by each of the remaining fossil fuels:

$$\frac{(\%RIC_x)(.7 \text{ or } .5 - CF_x) \times 100\%}{(\%RIC_c)(.7 - CF_c) + (\%RIC_o)(.5 - CF_o) + (\%RIC_g)(.5 - CF_g)} = \% \text{ Nuclear Energy Supplied by fuel } x$$

where, % RIC = Percentage of Regional Installed Capacity

CF = Capacity Factor

c = Coal

o = Oil

g = Gas

The data on regional capacity factors was extracted from the generation and capacity projections appearing in the NERC 9th Annual Review. ^{1/} Information on percentage, of Regional installed capacity was obtained from the 1980 Form FRA-411. Table VII-2-2 shows the projection of the percentage of "lost" nuclear energy that would be supplied by each fossil fuel (coal, oil, gas) in each Electric Region if the total "lost" energy were to be supplied by generating units in that region.

^{1/} 9th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System. NERC. August 1979.

Calculation of Additional Fossil Fuel Use

Once the amount of replacement energy for each fuel type for each region was calculated, the next step was to convert this energy to additional fossil fuel requirements.

It was assumed that additional coal fired generation would be at a 10,000 BTU/KWH heat rate; additional oil and gas generation was assumed to be 12,000 BTU/KWH. The heat content of fossil fuels was assumed to be 24 million BTU per ton for coal (12,000 BTU/lb), 1/ 6 million BTU per barrel for oil and 1 million BTU per MCF (thousand cubic feet) for gas.

Applying the above heat rates and heat contents to the additional fossil fuel generation yields additional fossil fuel consumption. Two effects were considered that modify the additional fossil fuel consumption;

- (1) The effects of energy shortages, and
- (2) The effects of inter-regional transfers.

The Effects of Energy Shortage on Fossil Fuel Consumption

Peak demand, energy requirements, and total capacity on an Electric Region basis was obtained from the April 1980 submissions of Form ERA-411 by the Reliability Councils. This information is provided by year and then divided into summer and winter. The projected nuclear unit capacities were subtracted from these values and adjusted seasonal yearly installed capacity reserve margins were calculated. Total reserve margin is defined as the difference between the total generating capacity (including net transactions) and peak customer demand and is stated either in MW or percent of peak demand.

In determining the ability of an Electric Region to replace lost nuclear generation, it was assumed that the maximum amount of replacement energy would be equivalent

1/ It is recognized that the national average heat content of coal has been less than 12,000 BTU/lb for several years. However, this is a reasonable

to the adjusted system capacity (without the nuclear units) operating at a 60% capacity factor, 1/ minus the actual system energy requirement. If this maximum amount of replacement energy is greater than the amount of lost nuclear energy, there is no energy shortage. If, however, the maximum amount of replacement energy is less than the lost nuclear energy, the difference is the energy shortage. This energy shortage will reduce the amount of additional fossil fuel consumed by permitting replacement of only part of the lost nuclear energy.

Therefore, the additional fuel use is the additional amount of coal, oil and gas needed to replace lost nuclear energy minus the amount of fuel that would have been required to supply that portion of lost nuclear energy identified as "energy shortage."

The Effects of Inter-regional Transfers on Energy Shortages and Fossil Fuel Consumption

This analysis examined the existing transmission grid to determine if a region with an energy shortage could import from another region having excess capacity. Only those regions with reserves greater than 12% in summer and winter were considered as possible energy exporters. These inter-regional transfers have the effect of reducing the energy shortage in importing region and increasing the coal, oil and gas use in the exporting region. Table VII-2-3 thru Table VII-2-7 take these two factors into account.

1/ A survey of unit capacity factors indicates that large base load fossil units operate with annual capacity factors in the 60%-70% range. Thus, it was felt that operating an entire system's installed capacity (including peak load generation) at 60% annual capacity factor would likely be an upper bound for the maximum energy one could expect from a system. Any energy requirement in excess of this upper bound would have to be served by another region's generation or else there would be unserved energy.

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TABLE VII-2-1
ANNUAL POTENTIAL LOST NUCLEAR ENERGY (GWH)
DUE TO OPERATING LICENSE DELAYS
BY ELECTRIC REGION

REGION	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	0	0
3. NEPOOL	0	0	0	4,307	5,742	12,190
4. NYPP	0	0	0	4,094	4,094	4,597
5. PJM	0	3,875	9,118	14,836	17,254	24,959
6. CECo	436	5,569	12,506	20,102	30,426	35,863
7. F.C.G.	0	0	0	662	3,970	4,457
8. MSU	0	0	9,762	11,784	13,231	17,912
9. So.Co.	1,342	4,030	4,524	4,524	5,481	10,267
10. GSU	0	0	0	0	3,520	4,694
11. TVA	0	5,303	15,037	20,931	29,223	33,560
12. VACAR	865	10,386	14,607	18,030	27,739	32,049
13. CAPCo	0	0	0	0	3,925	5,887
14. CCD	0	3,955	3,955	4,440	4,440	4,440
15. Kentucky	0	0	0	0	0	0
16. Indiana	0	0	0	0	0	0
17. ILL-MO	0	0	1,830	10,476	11,762	11,762
18. MECS	0	0	4,548	5,458	7,431	12,139
19. WUMS	0	0	0	0	0	0
20. MAPP	0	0	0	0	0	0
21. MO-KAN	0	0	0	4,307	5,742	6,447
22. Oklahoma	0	0	0	0	0	0
23. Texas	0	2,393	5,742	12,190	17,911	19,136
24. RMPP	0	0	0	0	0	0
25/30 NWPP	0	0	0	5,493	5,493	9,808
26. ARIZ-NM	0	0	0	3,699	10,569	13,461
27. So.Cal-Nev	0	1,373	5,493	11,660	11,660	12,334
28. No.Cal-Nev	0	7,263	10,935	12,278	12,278	12,278
Total Lost Energy	2,644	44,247	98,057	169,271	231,891	288,240
Total Energy Requirement ⁽¹⁾	2,347,337	2,456,116	2,567,436	2,677,637	2,795,454	2,909,107
% of Total Energy Requirement	0.11%	1.30%	3.82%	6.32%	8.30%	9.91%

(1) Data As Reported By The Regional Electric Reliability Councils To the Department of Energy, April 1, 1980, For The Contiguous United States.

TABLE VII-2-2
ALLOCATION OF FOSSIL ENERGY
TO REPLACE LOST NUCLEAR ENERGY

% Lost Nuclear Energy To Be Supplied By:

<u>Region</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
1. APS	90	10	0
2. AEP	100	0	0
3. NEPOOL	0	100	0
4. NYPP	5	95	0
5. PJM	15	85	0
6. CEC	45	55	0
7. F.C.G.	15	85	0
8. MSU	25	0	75
9. So.Co.	80	20	0
10. GSU	25	0	75
11. TVA	80	20	0
12. VACAR	70	30	0
13. CAPCo	95	5	0
14. CCD	100	0	0
15. Kentucky	100	0	0
16. Indiana	90	10	0
17. ILL-MO	80	20	0
18. MECS	55	45	0
19. WUMS	80	20	0
20. MAPP	70	30	0
21. MO-KAN	80	0	20
22. Oklahoma	40	0	60
23. Texas	20	0	80
24. RMPP	75	25	0
25/30 NWPP	25	75	0
26. ARIZ-NW	40	60	0
27. So.Cal-Nev	0	100	0
28. No.Cal-Nev	0	100	0

TABLE VII-2-3
EXPECTED ENERGY SHORTAGE (GWH)
IN CRITICAL REGIONS
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers To
Reduce Energy Shortage)

ELECTRIC REGION	1980	1981	1982	1983	1984	1985
10. GSU	0	0	0	0	1,183	186
23. Texas	0	0	0	0	1,219	2,744
28. No. Cal- Nev.	0	0	0	0	0	529
TOTAL	0	0	0	0	2,402	3,456

(1)
 Total NERC
 Energy 2,347,337 2,456,116 2,567,436 2,677,637 2,795,454 2,909,107

% of Total
 NERC
 Energy 0% 0% 0% 0% 0.09% 0.12%

(1) Data as reported by the Regional Electric Reliability Councils to the Department of Energy, April 1, 1980, for the contiguous United States.

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TABLE VII-2-4
REGIONS WITH CRITICALLY LOW TOTAL RESERVES^{1/}
ADJUSTED FOR INTERREGIONAL TRANSFER
IF NUCLEAR OPERATING LICENSE DELAYS CONTINUE
(PERCENT RESERVE MARGINS SUMMER/WINTER)

^{3/} ELECTRIC REGION	1980	1981	1982	1983	1984	1985
1. APS (2)					20 /11	14 /7
6. CECo			6 /51	2 /45	(2) /40	(6) /35
8. MSU					5 /39	3 /37
11. TVA				18 /12	10 /6	8 /4
12. VACAR						13 /11
13. CAPCo						11 /21
25&30. N.W.P.P.	37 /11	33 /9	33 /5	25 /8	32 /6	28 /7
26. ARIZ-NM					8 /47	8 /40
28. NO. CAL-NEV		4 /22	10 /25	8 /19	7 /13	6 /12

1/ The regions listed are those for which the summer or winter (or both) reserve margin is less than 12%, including net purchases and sales.

2/ No nuclear units are scheduled for this area in the 1980-85 period.

3/ These Electric Regions were delineated by ERA for the purpose of implementing the Power Plant and Industrial Fuel Use Act of 1978. The same regional arrangement is logical and useful for the analysis of electric power supply problems. Analysis of some power pools or control areas within these regions may show more severe problems because of local transmission constraints or generator availability.

4/ () denotes negative reserves.

TABLE VII-2-5
REGIONAL INCREASE IN COAL USE
DUE TO NUCLEAR LICENSING DELAYS

(Includes Impact of Inter-regional Transfers
to Reduce Energy Shortages)

PROBABLE ADDITIONAL COAL CONSUMPTION (TONS/DAY)

Region	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	4,300	9,600
3. NEPOOL	0	0	0	0	0	0
4. NYPP	0	0	0	200	200	300
5. PJM	0	700	1,600	2,500	3,000	4,300
6. CECO	200	2,900	6,400	10,300	15,100	16,900
7. P.C.G.	0	0	0	100	700	800
8. MSU	0	0	2,800	3,400	2,900	4,000
9. So.Co.	1,200	3,700	4,100	5,500	12,800	18,000
10. GSU	0	0	0	0	400	1,100
11. TVA	0	4,800	13,700	17,800	16,500	14,800
12. VACAR	700	8,300	11,700	14,400	22,200	25,600
13. CAPCO	0	0	0	0	3,900	4,800
14. CCD	0	4,500	4,500	5,100	5,100	5,100
15. Kentucky	0	0	0	0	0	1,800
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	1,700	9,600	11,700	11,700
18. MECS	0	0	2,900	3,400	4,900	8,600
19. WUMS	0	0	0	0	900	1,600
20. MAPP	0	0	0	0	0	1,000
21. MO-KAN	0	0	0	3,900	6,000	6,600
22. Oklahoma	0	0	0	0	400	400
23. Texas	0	500	1,300	2,800	3,800	3,700
24. RMPP	0	0	0	0	1,000	1,500
25/30. MWPP	0	0	0	1,600	1,600	3,300
26. ARIZ-NM	0	0	0	1,700	4,300	5,800
27. So.Cal-Nev	0	0	0	0	0	0
28. No.Cal-Nev	0	0	0	0	0	0
Total Increase	2,100	25,400	50,700	82,300	121,700	151,300
Equiv. BBLs/Day	8,400	101,600	102,800	329,200	486,800	605,200
Total NERC (1) Coal USC (Tons/ Day)	1,610,200	1,692,300	1,784,200	1,847,400	1,925,200	2,035,300
% of Total NERC Coal Use	0.1%	1.5%	2.8%	4.5%	6.3%	7.4%

(1) Data from "Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirements," NERC, July, 1979.

TABLE VII-2-6
REGIONAL INCREASE IN OIL USE
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers
to Reduce Energy Shortage)

PROBABLE ADDITIONAL OIL CONSUMPTION
(BBL/DAY)

REGION	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	0	0
3. NEPOOL	0	0	0	23,600	31,500	66,800
4. NYPP	0	0	0	21,300	21,300	23,900
5. PJM	0	18,000	42,500	69,100	80,400	116,200
6. CECo	1,300	17,100	37,700	60,600	88,600	99,200
7. F.C.G.	0	0	0	3,100	18,500	20,800
8. MSU	0	0	0	0	0	0
9. So. Co.	1,500	4,400	5,000	6,600	15,300	21,500
10. GSU	0	0	0	0	0	0
11. TVA	0	5,800	16,500	21,300	19,800	17,700
12. VACAR	1,400	17,100	24,000	29,600	45,600	52,700
13. CAPCo	0	0	0	0	1,000	1,200
14. CCD	0	0	0	0	0	0
15. Kentucky	0	0	0	0	0	0
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	0	0	1,200	1,200
18. MECS	0	0	11,200	13,500	19,100	33,600
19. WUMS	0	0	0	0	1,100	1,900
20. MAPP	0	0	0	0	0	2,100
21. MO-KAN	0	0	0	0	0	0
22. Oklahoma	0	0	0	0	0	0
23. Texas	0	0	0	0	0	0
24. RMPP	0	0	0	0	1,600	2,400
25/30 NWPP	0	0	0	22,600	22,600	47,700
26. Ariz-NM	0	0	0	12,200	31,000	42,000
27. So. Cal-Nev.	0	22,000	32,200	70,900	77,300	71,200
28. No. Cal-Nev.	0	25,300	57,900	77,100	70,700	75,300
Total Increase (1)	4,200	109,700	227,000	431,500	546,600	697,400
Total NERC Oil Use (BBL/DAY)	1,852,300	1,974,900	2,036,300	2,027,600	2,001,600	2,082,500
% of Total NERC Oil Use	0.2%	5.6%	11.1%	21.3%	27.3%	33.5%

(1) Data from "Summary of Projected Peak Load, Generating Capability, and fossil fuel Requirements", NERC, July, 1979.

Table VII-2-7
REGIONAL INCREASE IN GAS USE
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers
to Reduce Energy Shortage)

PROBABLE ADDITIONAL GAS CONSUMPTION (MCF/DAY)

REGION	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	0	0
3. NEPOOL	0	0	0	0	0	0
4. NYPP	0	0	0	0	0	0
5. PJM	0	0	0	0	0	0
6. CECO	0	0	0	0	0	0
7. F.C.G.	0	0	0	0	0	0
8. MSU	0	0	240,700	290,600	252,200	346,100
9. So. Co.	0	0	0	0	0	0
10. GSU	0	0	0	0	38,200	91,700
11. TVA	0	0	0	0	0	0
12. VACAR	0	0	0	0	0	0
13. CAPCo	0	0	0	0	0	0
14. CCD	0	0	0	0	0	0
15. Kentucky	0	0	0	0	0	0
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	0	0	0	0
18. MECS	0	0	0	0	0	0
19. WUMS	0	0	0	0	0	0
20. MAPP	0	0	0	0	0	0
21. MO-KAN	0	0	0	28,300	42,900	47,600
22. Oklahoma	0	0	0	0	15,600	15,600
23. Texas	0	62,900	151,000	320,600	439,000	431,100
24. RMPP	0	0	0	0	0	0
25/ NWPP	0	0	0	0	0	0
30						
26. ARIZ-NM	0	0	0	0	0	0
27. So. Cal-Nev.	0	0	0	0	0	0
28. No. Cal-Nev.	0	0	0	0	0	0
Total Increase	0	62,900	391,700	639,500	787,900	932,100
Equivalent BBL/ Day	0	10,500	65,300	106,600	131,300	155,400
(1)						
Total NERC Gas (MCF/Day)	6,649,700	5,776,100	5,413,200	5,263,200	5,068,700	4,223,400
Total % of NERC Gas Use	0%	1.1%	7.2%	12.2%	15.5%	22.1%

(1) Data from "Summary of Projected Peak Load Generating Capability, and Fossil Fuel Requirements", NERC, July, 1979.

Table VII-2-8
Nuclear Units Affected by an Operating
License Delays Through 1985

ELECTRIC REGION NO. - NAME	UNIT NAME	SUMMER CAPACITY (MW)	PROJECTED ^{1/} IN-SERVICE DATE
			MONTH-YEAR
3-NEPOOL	SEABROOK #1	1,150	4-83
	SEABROOK #1	1,150	2-85
	PILGRIM #2	1,150	12-85
4-NYPP	SHOREHAM #1	820	1-83
5-PJM	3 MILE IS. #1	776	1-81
	SUSQUEHANNA #1	1,050	1-82
	SUSQUEHANNA #2	1,050	1-83
	HOPE CREEK #1	1,066	9-84
	LIMERICK #1	1,055	5-85
6-CECO	LA SALLE #1	1,048	12-80
	LA SALLE #2	1,048	12-81
	PYRON #1	1,120	10-82
	BRAIDWOOD #1	1,090	10-83
	PYRON #2	1,120	10-83
	BRAIDWOOD #2	1,090	10-84
7-FCG	ST. LUCIE #2	795	11-83
8-MSU	GRAND GULF #1	1,250	4-82
	WATERFORD #3	1,110	2-82
	GRAND GULF #2	1,250	4-85
9-SoCo.	FARLEY #2	807	9-80
	VOGTLE #1	1,150	11-84
10-GSU	RIVER BEND #1	940	4-84
11-TVA	WATTS BAR #1	1,177	9-81
	SEQUOYAH #2	1,148	6-81
	WATTS BAR #2	1,177	6-82
	BELLEFONTE #1	1,213	9-83
	BELLEFONTE #2	1,213	6-84
	YELLOW CREEK #1	1,285	11-85

Table VII-2-8 (cont'd)
Nuclear Units Affected by an Operating
License Delays Through 1985

ELECTRIC REGION NO. - NAME	UNIT NAME	SUMMER CAPACITY (MW)	PROJECTED ^{1/} IN-SERVICE DATE
			MONTH-YEAR
12-VACAR	MC GUIRE #1	1,180	12-80
	SUMMER #1	900	12-80
	MC GUIRE #2	1,180	7-82
	CATAWBA #1	1,145	12-83
	CATAWBA #2	1,145	7-85
	HARRIS #1	900	3-84
13-CAPCO	PERRY #1	1,179	5-84
14-CCD	ZIMMER #1	792	1-81
17-ILL-MO.	CALLOWAY #1	1,150	10-82
	CALLOWAY #2	948	12-82
18-MECS	MIDLAND #2	783	9-84
	FERMI #2	1,093	3-82
	MIDLAND #1	505	3-85
21-MOKAN	WOLF CREEK #1	1,150	4-83
23-TIS	COMANCHE PEAK #1	1,150	8-81
	COMANCHE PEAK #2	1,150	1-83
	SOUTH TEXAS #1	1,250	2-84
25-NWPP	WNP #2	1,100	1-83
	WNP #1	1,250	6-85
26-ARIZ-NM.	PALO VERDE #1	1,270	6-83
	PALO VERDE #2	1,270	5-84
27-So. Cal-Nev.	SAN ONOFRE #2	1,100	10-81
	SAN ONOFRE #3	1,100	1-83
28-No Cal. Nev.	DIABLO CANYON #1	1,084	2-81
	DIABLO CANYON #2	1,106	8-81

^{1/} In-service dates as projected by the Regional Electric Reliability Councils April 1, 1980, updated by ERA staff where possible to reflect most recent schedules.

TABLE VII-2-9
NUCLEAR UNIT PRIORITY LIST BY YEAR
1980-85

<u>ELECTRIC REGION</u>	<u>UNIT NAME</u>	<u>SUMMER CAPABILITY (MW)</u>	<u>PROJECTED COMMERCIAL OPERATION DATE</u>	<u>YEAR-BY-YEAR WEIGHTED RANK (1)</u>	<u>POTENTIAL OIL SAVED BBL/DAY (3)</u>
<u>UNITS SCHEDULED FOR 1980</u>					
6	LaSalle #1	1048	12/80	1	15,800
12	McGuire #1	1180	12/80	2	9,700
12	Summer #1	900	12/80	3	7,400
9	Farley #2	807	9/80	4	4,400
<u>UNITS SCHEDULED FOR 1981</u>					
28	Diablo Canyon #2	1106	8/81	1	30,300
28	Diablo Canyon #1	1084	2/81	2	29,700
6	LaSalle #2	1048	12/81	3	15,800
11	Sequoyah #2	1148	6/81	4	6,300
11	Watts Bar #1	1177	9/81	5	6,400
23	Comanche Peak #1	1150	8/81	6	0
27	San Onofre #2	1100	10/81	7	30,100
5	Three Mile Island #1	776	1/81 (2)	8	18,000
14	Zimmer #1	792	1/81	9	0
<u>UNITS SCHEDULED FOR 1982</u>					
6	Byron #1	1120	10/82	1	16,900
12	McGuire #2	1180	7/82	2	9,700
11	Watts Bar #2	1177	6/82	3	6,400
8	Waterford #3	1110	2/82	4	0
8	Grand Gulf #1	1250	4/82	5	0
5	Susquehanna #1	1050	1/82	6	24,400
18	Fermi #2	1093	3/82	7	13,500
17	Calloway #1	1150	10/82	8	6,300
17	Calloway #2	948	12/82	9	5,200
<u>UNITS SCHEDULED FOR 1983</u>					
25	WNP #2	1100	1/83	1	22,600
26	Palo Verde #1	1270	6/83	2	20,800
6	Byron #2	1120	10/83	3	16,900
6	Braidwood #1	1090	10/83	4	16,400
12	Catawba #1	1145	12/83	5	9,400
11	Bellefonte #1	1213	9/83	6	6,600
23	Comanche Peak #2	1150	1/83	7	0
3	Seabrook #1	1150	4/83	8	31,500
27	San Onofre #3	1100	1/83	9	30,100
5	Susquehanna #2	1050	1/83	10	24,400
	Shoreham #1	820	1/83	11	21,300

TABLE VII-2-9
NUCLEAR UNIT PRIORITY LIST BY YEAR
1980-85

<u>ELECTRIC REGION</u>	<u>UNIT NAME</u>	<u>SUMMER CAPABILITY (MW)</u>	<u>PROJECTED COMMERCIAL OPERATION DATE</u>	<u>YEAR-BY-YEAR WEIGHTED RANK (1)</u>	<u>POTENTIAL OIL SAVED (3) BBL/DAY</u>
<u>UNITS SCHEDULED FOR 1983 (CONT'D)</u>					
7	St. Lucie #2	795	11/83	12	18,500
21	Wolf Creek #1	1150	4/83	13	0
<u>UNITS SCHEDULED FOR 1984</u>					
26	Palo Verde #2	1270	5/84	1	20,800
6	Braidwood #2	1090	10/84	2	16,400
12	Harris #1	900	3/84	3	7,400
11	Bellefonte #2	1213	6/84	4	6,600
13	Perry #1	1179	5/84	5	1,600
23	South Texas #1	1250	2/84	6	0
10	River Bend #1	940	4/84	7	0
5	Hope Creek #1	1066	9/84	8	24,800
18	Midland #2	783	9/84	9	9,600
9	Vogtle #1	1150	11/84	10	6,300
<u>UNITS SCHEDULED FOR 1985</u>					
25	WNP #1	1250	6/85	1	25,700
12	Catawba #2	1145	7/85	2	9,400
11	Yellow Creek #1	1285	11/85	3	7,000
3	Seabrook #2	1150	2/85	4	31,500
8	Grand Gulf #2	1250	4/85	5	0
3	Pilgrim #2	1150	12/85	6	31,500
5	Limerick #1	1055	5/85	7	24,500
18	Midland #1	505	3/85	8	6,200

- (1) Rank is based on a weighted factor which considers oil saving potential, energy shortage, and low reserve margins; and is only valid within a given year. For licensing purposes, it may be desirable to give preference to top ranked units in a subsequent year over the lower ranked units in the current year.
- (2) Three Mile Island #1 has been shutdown for an indefinite period because of the accident at Three Mile Island #2. January 1981 was assumed by ERA staff to be the earliest possible on-line date.
- (3) Potential oil saved assuming a full year of operation at 57% capacity factor, divided by 365. Total oil saved the first year depends on the number of days of operation. These figures reflect an adjustment to account for the regional dependency on oil.

TABLE VII-2-10

(1)

Lower Growth Rates Assumed by ERA Staff
For Sensitivity Studies
1980-1985

<u>Electric Region</u>	<u>Peak Demand Growth Rate 1980-85 (Council Projection)</u>	(1) <u>Lower Growth Rate Assumed by ERA Staff 1980-85</u>
1 - APS	4.6% (Winter)	2.6%
6 - CECO	4.4% (Summer)	1.7%
8 - MSU	5.6% (Summer)	4.8%
10 - GSU	6.0% (Summer)	5.2%
11 - TVA	4.0% (Winter)	1.0%
12 - VACAR	5.1% (Summer)	1.0%
13 - CAPCO	3.7% (Summer)	2.1%
23 - TEXAS	5.2% (Summer)	3.5%
25/30 - NWPP	4.3% (Winter)	2.2%
26 - ARIZ - NM	6.3% (Summer)	3.3%
28 - No.Cal-Nev	3.3% (Summer)	1.7%

(1) Same growth rate assumed for peak demand and energy.

TABLE VII-2-11
Regions with Critically Low Total Reserves
(Adjusted for Net Purchases and Sales) if Nuclear Operating
License Delays Continue

(Percent Reserve Margins Summer/Winters)
 (Low Growth Rate Scenario)

2/

Electric Region	1980	1981	1982	1983	1984	1985
6. CECO				11/56	9/53	7/51
8. MSU					8/44	7/42
28. No.Cal-Nev		5/25		11/25		

-
- 1/ The regions listed are those for which the summer or winter (or both) reserve margin is less than 12% including net purchases and sales. Lower growth rates than those projected by the utilities were assumed in computing these reserves - see text.
- 2/ These Electric Regions were delineated by ERA for the purpose of implementing the Power Plant and Industrial Fuel Use Act of 1978. The same regional arrangement is logical and useful for the analysis of electric power supply problems. Analysis of some power pools or control areas within these regions may show more severe problems because of local transmission constraints or generator availability.

VIII. TRANSMISSION

Transmission facilities are of great importance in establishing electric system reliability because they knit together the power-producing generating facilities and the power-consuming devices of the system customers. Transmission, in a sense, constitutes the fabric of a power system; the strength and function of each line is supported by that of every other line in the whole complex. The dispersion of transmission lines and equipment throughout the entire service area of a system, and the interdependence of the lines, make the adequacy of transmission more difficult to evaluate than the adequacy of generation.

Generating facilities are concentrated at points in a system's area; generating capacities are independent of one another and can be added to obtain a meaningful total. On the other hand, transmission facilities are spread over the entire system area; transmission line capacities are interdependent to a certain extent; transmission line capacities cannot be added to obtain a meaningful total. It is because transmission lines form a network of paths over which electricity may flow, in which each line flow must be considered in relation to every other line flow, that the mathematical analysis of transmission reliability is more complex.

In the analysis of generating capacity adequacy, there are several generally accepted measures that provide at least an approximate index of sufficiency, but no such indices are available for the transmission function. One quantifiable measure of the transmission system is the number of miles of line. Table VIII.1 is a summary of the Council projections of lines to be added at various voltage levels. The construction of additional transmission lines implies that the ability to transfer power within a region and between regions becomes greater, but this is not necessarily the case in all instances. Line location on the system is a major factor in determining the degree of improvement effected. That is, the terminals of the line (the points on the system which it ties together) must be considered in an evaluation of the line's contribution to reliability. The lines whose mileage is summarized in Table VIII.1 constitute only those considered significant for interconnected operation of the systems reporting. Additional construction for various local purposes may also be planned.

VIII.2

Every transmission line serves at least one purpose; some may serve multiple purposes. As indicated in the Council reports the functions of the lines reported can be grouped under the following headings:

1. Increased interchange capability
2. Provide a path for moving generator output into the system.
3. Improve system stability. This function may also improve the power transfer capability of this system.
4. Relieve overloads on existing lines by providing alternate paths for power to flow over.
5. Provide ability to serve anticipated load increases.
6. Provide general support to an area. This could include provision for some future loads, relief of existing overloads, voltage improvement, flexibility to permit maintenance outages, greater power transfer capability to an area.
7. Improve voltage level at some specific substation.

VIII.3

It is recognized that lines constructed for higher voltages have greater capability for transfer of power than lines constructed for lower voltages. However, line capacity is determined by other factors in addition to the voltage. 1/ Considerations which modify transfer capability are at least the following: number of conductors; conductor size and type; the length of the line; the ambient temperature range in which the line operates; the limitations of the facilities (circuit breakers, transformers, etc.) at the terminals; the network of lines into which the line is placed; the generating facility characteristics of the system; the effect on system stability, and on loading of other lines, if the line should fail in service; allowable voltage difference (magnitude and phase angle) between the line terminals. 2/ Several examples can be cited of the effect of these considerations on the allowable loading of a line. These examples are cited only to illustrate practical situations arising in the planning and operation of large power networks; no evaluation, criticism or approval of specific instances is intended or implied.

1/Power Technologies, Inc., Report for Electric Power Research Institute, "Synthetic Electric Utility Systems for Evaluating Advanced Technologies", EPRI EM-285, February, 1977, pp. 439-444.

2/ R.D. Dunlop, R. Gutman, P.P. Marchenko, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," I.E.E.E. Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979, pp. 606-617, and correction in Vol. PAS-98, No. 3, May/June 1979, p. 699.

VIII.4

1. Alabama Power Co. (Southern Co. area of SERC)

Schedule 18B of the 1979 Form 12 Report lists lines operating at 500 Kv, 230 Kv, 161 Kv and 115 Kv. One 500 Kv line has a maximum possible loading of 1,225 MW. Another, shorter, 500 Kv line has a maximum possible loading of 1,195 MW, limited by transformer capacity. The maximum possible loadings of the 230 Kv lines range from 280 MW to 986 MW, with several of the lines being limited by transformer capacity. For the 161 Kv lines the maximum possible loading runs from 112 MW to 192 MW. At the 115 Kv level the heaviest loading allowable is 274 MW on a line 3.24 miles long; the minimum loading allowed is 53 MW on a 20.40 mile line, with loading limited by a transformer. Several lines are load-limited because of disconnect switch ratings.

2. Central Hudson Gas & Electric Corp. (New York Power Pool in NPCC)

Schedule 18B of the 1979 Form 12 lists three lines of 345 Kv, of lengths from 17 miles to 30 miles, each with maximum possible loading of 1,589 MW. Many 115 Kv lines at various maximum allowable loadings from 93 MW to 265 MW are listed.

3. Cincinnati Gas & Electric Co. (ECAR)

Schedule 18B of the 1979 Form 12 lists six 345 Kv lines from 3.68 to 23.33 miles long. Four of these lines have a maximum possible loading of 1,235 MW, limited by line trap ¹/ rating; one line has a maximum possible loading of 1,270 MW, limited by a current transformer ²/ rating; one line is limited to only 440 MW because of power transformer capacity limitations. Additional 345 Kv lines have maximum possible loadings between 559 MW and 1,375 MW, limited by power transformers, current transformers, line traps or disconnect switches. A number of 138 Kv lines are listed, with maximum possible loadings from 58 MW (limited by generating station capacity) up to 382 MW.

1/ A line trap is a device connected to a transmission line in association with carrier current communication equipment.

2/ A current transformer is a transformer used in association with metering and relaying equipment.

VIII.5

The 3 illustrations above show that line capability is not necessarily determined solely by voltage level. Alabama Power Co. has lines at 500 Kv with maximum possible loading less than that of several 345 Kv lines reported by Cincinnati Gas & Electric Co. Conversely, Alabama Co. has some 230 Kv lines with maximum possible loading greater than that of some 345 Kv lines on the Cincinnati Gas & Electric System.

Transmission capacity should in general be sufficient to transmit all generated power from generating plants to loads at reasonably small voltage drops and energy losses; maintain stability under various contingencies; allow for inter-utility transfers of power and energy both intra-regionally and inter-regionally so as to facilitate over-all economic operation and assistance in emergencies. Transmission facilities in appropriate circumstances may partially substitute for generating capacity, but such substitution must be carefully considered in relation to the need for adequate over-all installed (planned) and operating reserves. A transmission line cannot create electric energy but could overcome a local supply problem and eliminate the need for a small generating unit.

As discussed above, transmission system reliability is strongly affected by topological considerations as well as by the characteristics of individual circuits and items of equipment. Just as the reliability of power supply from generating units is closely related to the probability of forced outages and reduction of capacity, and the time pattern of maintenance outages, the reliability of the transmission network is related to the probability of line and equipment forced outages and maintenance outages. 1/ The mathematical complexity of the necessary system analyses, the uncertainties associated with the parameters and data, the uncertain correspondence between models and reality, and the flexibility of utility operating procedures in unforeseen circumstances, all have an effect on transmission system reliability.

1/ L. Wang, "The Effects of Scheduled Outages in Transmission System Reliability Evaluation." I.E.E.E. Transactions on Power Apparatus and Systems, Vol. PAS-97, No. 6, Nov./Dec. 1978, pp. 2346-2353.

VIII.6
Table VIII.1
Projected Bulk Power Transmission Lines 1980-1989
Significant For Interconnected Operation
As Reported by the Regional Electric Reliability Councils
April 1, 1980

<u>Miles of Line at Each Voltage Level*</u>						
<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	327	2,998	302	1,194	-0-	4,821
MAAC	943	16	459	-0-	-0-	1,418
MAIN	-0-	1,325	55	-0-	-0-	1,380
MARCA ^{5/}	1,378	2,463	1,348	0	1,823 ^{1/}	7,012
NPCC ^{5/}	8	1,141	-0-	74	494 ^{2/}	1,717
SERC	3,818	0	2,596	2	26 ^{3/}	6,442
SWPP	<u>2,508</u>	<u>3,409</u>	<u>1,292</u>	<u>-0-</u>	<u>-0-</u>	<u>7,209</u>
Subtotal	8,982	11,352	6,052	1,270	2,343	29,999
WSCC ^{6/}	5,812	4,426	7,740	0	2,070 ^{4/}	20,048
ERCOT	<u>-0-</u>	<u>3,311</u>	<u>-0-</u>	<u>-0-</u>	<u>-0-</u>	<u>3,311</u>
U.S. Total	14,794	19,089	13,792	1,270	4,413	53,358

*All voltages are A.C. unless otherwise stated.

1/ 835 miles at 115 Kv and 988 miles at 161 Kv.

2/ 115 and 138 Kv.

3/ 10 miles at 69 Kv; 10 miles at 115 Kv; 6 miles at 138 Kv.

4/ 69 miles at 115 and 161 Kv; net of 800 Kv D.C. upgraded to 1000 Kv D.C., and additional 1000 Kv D.C. construction; (-41) miles at 287 Kv.

5/ U.S. portion of Council only.

6/ Includes projected lines of Canadian systems. Revised totals as reported by WSCC on May 12, 1980.

IX Inter-Regional Transfers

At the time that the Reliability Council annual reporting arrangements were initiated,^{1/} there was great interest in the magnitude of feasible inter-regional transfers of power under normal and emergency conditions. The reports therefore provide information on scheduled transfers in Item 2C, and on emergency transfer capability in Item 6A. Scheduled transfers are those for which arrangements have been made in advance as to magnitude and time of occurrence. Emergency transfers by their very nature cannot be scheduled in advance.

A. Scheduled Transfers

Electric utilities arrange well in advance 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 for the period of the expected diversity. An example of diversity interchange is the agreement between TVA and the South Central Electric Companies (SCEC) group. This agreement, negotiated in the 1960's, called for TVA to provide 1500 MW and associated energy to SCEC during the summer and for SCEC to provide 1500 MW

1/ Federal Power Commission Order 383-2, April 10, 1970.

IX.2

and associated energy to TVA during the winter.^{1/} Changes in the diversity between the two areas involved have led to a reduction in the amount of the exchange. From the winter of 1981-82 on, the capacity exchanged will be only 700 MW.

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 recognition of the opportunities for such arrangements.

The inter-utility transactions in capacity, when effected between members of one Council, will not in general change the Council area reserve margin (although area capacity will be more effectively used). When the utilities participating in a capacity exchange are in two different Councils or in different electric 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. Table IX.1 summarizes data on net inter-regional capacity transfers scheduled for the winter and summer peak periods from summer 1980 through winter 1989-90.

There are large differences among the Councils in the pattern of capacity transfers. ECAR shows a net export of power, both winter and summer, for the entire period. WSCC shows only a small net export in summer 1980, with minor net imports for 1981, 1982 and 1983. After the summer of 1983 WSCC has zero net transfers through 1989-90 winter. Like ECAR, SERC power transfers result in a net export in each summer of the study period, but unlike ECAR, the net transfer is into SERC in each winter period. The patterns of the other Councils are also different.

^{1/} See I.E.E.E. Transactions on Power Apparatus and Systems, November 1967, Vol. PAS-86, No. 11 ---
H.R. Koen, Jr., "South Central Electric Companies Information Processing System," pp. 1334-1343.
T.C. Erwin, R.E. Linton, T. Niessink, "EHV Protective Relaying on SCEC Systems." pp. 1384-1388.

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 generating unit construction, projected loads, transmission availability and system operating considerations, among other things.

In some instances, projected capacity transfers may require construction of new facilities, or agreements to "wheel" power through the facilities of a utility which is neither the provider nor the user of the power. When power is wheeled from one utility to another through a third utility's system, adequate consideration must be given to the effects upon the wheeling system. These effects may include distortion of normal power flow and voltage patterns, increased losses, overloads of some facilities at certain times, or stability problems.

B. Emergency Transfers

Emergency transfer of power from one region to another may be needed for various reasons whose nature can be described, but whose time of occurrence cannot be specified in advance. These reasons include large-scale loss of generating capacity, transmission system accidents, unforeseen increases in demand, or other situations in which a region finds that its total of generating capacity and net scheduled purchases is significantly less than its customer demand. The situation may affect an entire region or may be localized to some part of a region.

The magnitude and occurrence of need for emergency power transfers are random quantities. The data reported in Item 6A relate only to the probable maximum emergency capability available. In the determination of the power flows possible, complex mathematical and engineering analyses are needed, involving theoretical and practical considerations. 1/ The meaning of "Emergency Transfer Capability" is defined by the Regional Councils as - "The total amount of power (above the net contracted purchases and sales) which can be scheduled with an assurance of adequate system reliability, for interregional or multiregional transfers over the transmission network for periods up to several days, based on the most limiting of the following 2/:

- 1/ G.L. Landgren, S.W. Anderson, R. White, "A Reliability Approach To Interconnection Planning," I.E.E.E. Transactions on Power Apparatus and Systems, Vol. PAS-94, No. 5, Sept./Oct. 1975, pp. 1644-1651.
- 2/ National Electric Reliability Council "9th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System" August 1979.

IX.4

- (A) All transmission loadings initially within long-time emergency ratings and all voltages initially within acceptable limits.
- (B) The bulk power system capable of absorbing the initial power swings and remaining stable upon the loss of any single transmission circuit, transformer or generating unit.
- (C) All transmission loadings within their respective short-time emergency ratings and voltages within emergency limits after the initial power swings following the disturbance, but before system adjustments are made. (In the event of a permanent outage of a facility, transfer schedules may need to be revised.)"

It is apparent from the definition of Emergency Transfer Capability that complete reliance upon emergency transfers as a substitute for adequate generating capacity reserves within a region would not result in reliable power supply. Under the definition given, studies of power flows can be made that will yield an approximation to the maximum power transferable from one Council region to another under specified conditions. The results of the studies, as reported by the Reliability Councils, are shown in Table IX.2 below. In a review of the maximum emergency support that any Council area could obtain from adjacent Councils, the non-simultaneous nature of the transfers must be kept in mind. The physical laws that govern power transfer over a large interconnected network of utilities cannot be evaded. Circuit conditions that permit maximum power flow from one region to another will in general be different for different pairs of regions. For instance, the circuit conditions under which SERC could receive maximum emergency power from ECAR are not necessarily the same as those which would allow SERC to receive maximum power flow from SWPP. Therefore, the maximum emergency power that SERC could receive from those regions together would not be the sum of the powers transferable from ECAR and SWPP separately.

Table IX.1
PROJECTED NET SCHEDULED INTER-REGIONAL EXCHANGES OF CAPACITY, SUMMER AND WINTER
1980-1989
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
TO THE DEPARTMENT OF ENERGY--APRIL 1, 1980 1/
CONTIGUOUS UNITED STATES

Summer Peak Period - Net of Scheduled Imports and Exports (Mw) 2/ 3/										
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ECAR 4/	(806)	(777)	(874)	(906)	(644)	(631)	(338)	(345)	(352)	(47)
ERCOT	145	550	550	604	575	703	680	665	665	665
MAAC	157	107	107	107	107	107	107	107	107	107
MAIN 6/	1,066	1,246	585	272	267	267	136	135	(61)	(62)
MARCA 5/	670	565	525	660	651	643	738	730	626	615
NPCC 5/	1,277	1,270	1,274	1,276	1,280	1,263	1,064	864	863	863
SERC	(1,060)	(1,060)	(660)	(660)	(660)	(660)	(960)	(960)	(960)	(960)
SWPP 6/	518	(36)	206	173	(298)	(375)	(201)	(186)	(185)	(300)
WSCC 5/	(36)	182	75	75	0	0	0	0	0	0

Winter Peak Period - Net of Scheduled Imports and Exports (Mw) 2/ 3/										
	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90
ECAR 4/	(105)	(276)	(278)	(39)	(48)	(33)	(339)	(345)	(40)	(46)
ERCOT	145	550	550	604	575	703	680	665	665	665
MAAC	157	107	107	107	107	107	107	107	107	107
MAIN 6/	537	367	66	(247)	(250)	(251)	(381)	(382)	(578)	(579)
MARCA 5/	(184)	(219)	(291)	(228)	(235)	(240)	(246)	(353)	(356)	(264)
NPCC 5/	450	452	453	455	436	236	36	35	35	35
SERC	660	660	660	660	660	660	960	960	960	960
SWPP 6/	(1,282)	(1,436)	(1,193)	(727)	(698)	(775)	(601)	(586)	(585)	(700)
WSCC 5/	31	75	75	0	0	0	0	0	0	0

1/ From Item 2C of the Council reports. In some instances the data include capacity exchanges between members of a Council and non-members within the geographic boundaries of that Council.

2/ Net = Imports - Exports.

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.

4/ Total of Bulk Power and Liaison System Members.

5/ U. S. portion of Council only. Does not include exchanges occurring within Canada.

6/ Data do not reflect transfer of Associated Electric Cooperative (AEC) from MAIN to SWPP due to a discrepancy in capacity exchanges reported for AEC.

Table IX.2
Inter-Council Emergency Transfer Capability
As Reported April 1, 1980
By The Regional Reliability Councils

<u>Direction of Power Flow</u>		<u>Emergency Transfer Capability-MW</u>
<u>From</u>	<u>To</u>	<u>Summer 1979</u>
ECAR	MAAC	3300 (4350 in 1984)
ECAR	NPCC (NYPP)	2200 (1950 in 1984)
ECAR	MAIN	3450 (2900 in 1984)
ECAR	SERC (TVA)	1800
ECAR	SERC (VACAR)	1250 (2200 in 1980)
NPCC (NYPP)	ECAR	3300 (2900 in 1984)
NPCC	MAAC	2250 (in 1984)
MAIN	ECAR	4000 (4000 in 1984)
MAIN	MARCA	1000 (550 in 1984)
MAIN	SERC (TVA)	750 (3200 in 1984)
MAIN	SPP	2000 (1800 in 1984)
MAAC	ECAR	2450
MAAC	NPCC	1650 (in 1984)
MAAC	SERC (VACAR)	1800 (in 1980)
MARCA	MAIN	600 (800 in 1984)
MARCA	WSCC	100 1/
MARCA	SPP	700 (in 1980)

1/ Total of scheduled and emergency capability

Table IX.2 (continued)

<u>Direction of Power Flow</u>		<u>Emergency Transfer Capability, MW</u>
<u>From</u>	<u>To</u>	<u>Summer 1979</u>
SERC (TVA)	ECAR	2000
SERC (VACAR)	ECAR	2700 (3300 in 1980)
SERC (VACAR)	MAAC	2000 (4850 in 1984)
SERC	MAIN	1100 (2800 in 1984)
SERC	SPP	1550 (in 1980; 4000 in 1984)
SPP	SERC (TVA)	2650 (in 1980; 3000 in 1984)
SPP	MARCA	800
SPP	MAIN	2000 (1900 in 1984)
WSCC	MARCA	100 (in 1980 and in 1985)
WSCC (U.S.)	WSCC (Canada)	2000 (in 1980 and in 1985) <u>1/</u>
WSCC (Canada)	WSCC (U.S.)	2000 (in 1980 and in 1985) <u>1/</u>

Note: All transfers to a Council (or from a Council) are not simultaneous. The total of all transfers to a Council (or from a Council) does not represent the total emergency power actually transferable because circuit conditions are different for each individual transfer.

1/ Total of scheduled and emergency capability.

X. COAL UNIT DELAYS

Introduction

This analysis is an update of the Division of Power Supply and Reliability staff report dated March 24, 1980, 'The Effects of Delays in Construction of Coal-Fired Generating Units on Electric Utility Use of Coal, Oil and Natural Gas'. The time period covered is 1980 through the end of 1989.

Summary

This report compares coal unit completion schedules as reported in the April 1, 1979 and April 1, 1980 Coordinated Planning Reports of the nine Regional Electric Reliability Councils. The data in the Council Reports is as of December 31, 1978 and December 31, 1979, respectively.

In the twelve-month period covered by the two sets of reports, schedules were changed for 100 coal-fired generating units totalling 52,676 mw. Completion time was shortened for 10 units totalling 4,794 mw and was lengthened for 90 units totalling 47,882 mw. In terms of megawatt-months (defined as the algebraic sum of the products of each unit's capability multiplied by the number of months change in its completion schedule), there was a cumulative gain of 41,104 mw-m and a loss of 692,630 mw-m, resulting in a net loss of 651,526 mw-m. Eighty-six of the schedule changes involve units 300 mw or larger. Coal units have been delayed in every Council Region.

The net loss of 651,526 mw-m in coal-supplied energy, for the years 1980 through 1989, will result in the use of additional oil and natural gas.

Ten units whose early completion would appear to offer the greatest benefits in reduction of oil consumption (approximately 76 million barrels) are offered as candidates for accelerated construction. These units are: Brandon Shores No. 2, Brandon Shores No. 1, Sears Island, Seward No. 7, California Coal No. 1, California Coal No. 2, Coho No. 1, H. Allen No. 1, H. Allen No. 2, and H. Allen No. 3.

X.2

Ten units whose early completion would appear to offer the greatest benefits in reduction of gas usage (approximately 324 million mcf ^{1/}) are listed as candidates for accelerated construction: Forest Grove No. 1, Twin Oak No. 1, Unsited No. 1, R. S. Nelson No. 5, Coletto Creek No. 2, Muskogee No. 6, Unsited No. 1, Pirkey No. 1, F. P. P. No. 3, and Lovelady No. 1.

Oil and gas savings could also be realized if completion schedules were advanced for those units currently showing no delays.

Details

Table X.1 is a summary of the changes in coal unit scheduled in-service dates. It shows that the changes range from advancement of 18 months to delay of 48 months. The total capacity delayed is 47,882 mw, distributed among 79 units 300 mw or larger and 11 units of size less than 300 mw. Of the 10 units whose schedules have been advanced, 7 are in the 300 mw or larger category; 3 are smaller than 300 mw in size. The table also shows, for each category of delay or advancement, the total megawatt-months in that group.

Tables X.2 and X.3 are detailed listings showing for each unit the net expected capability and the in-service dates as reported in the April 1, 1979 and April 1, 1980 Council Reports. The tables also show the total megawatt-months associated with the schedule change of each unit listed. Table X.2 lists units 300 mw or larger; Table X.3 lists those smaller than 300 mw.

The additional oil that could be consumed because of a coal unit delay depends upon the capability of the unit and the "mix" of generating capacity of the system on which the unit operates, among other things. For the purposes of this report, it was assumed that the "system" would be the Electric Region in which the unit is located. The oil consumption also depends upon the capacity factor of the unit and upon the average use of oil per megawatt-hour of generation in the region. The "mix" of generating capacity for each region, as determined by analysis of installed capacity and probable incremental loading considerations, is shown in Table VII-2-2. This table, which was developed for the nuclear capacity analysis of this report (Section VII), is considered satisfactory for use in this analysis. The potential oil consumption due to each coal unit was computed by means of the following formula:

1/ One mcf = 1,000 cubic feet.

Barrels displaced = $C \times 732 \times CF \times 1.7 \times M \times MO$ (1)
 where

C = unit capability in megawatts

732 = number of hours in a month

CF = capacity factor, assumed here as 0.60

1.7 = U.S. average barrels of oil burned per megawatt-hour generated^{1/}.
 This differs from region to region, but the average U. S. value was assumed satisfactory for this report.

M = regional generation by oil, as a decimal fraction of total generation, shown in Table VII-2-2.

MO = months change in schedule

The results of the application of (1) to each of the coal units whose schedule was changed were used to produce a list of the ten units that would make a significant contribution to oil conservation (Table X.4).

The list of ten units whose early completion would make a large contribution to gas conservation (Table X.5) was obtained by the application of (1) with two modifications. The number 1.7 was replaced by 10.5 (U.S. average mcf of gas burned per megawatt-hour generated^{1/}), and regional generation by oil as expressed in M above was replaced by the regional generation by gas, as a decimal fraction of total generation, as shown in Table VII-2-2.

^{1/}-----Average of data reported on FPC Form 4 (Monthly Power Plant Report) by electric utilities for the years 1977, 1978, and 1979.

Table X.1

SUMMARY OF CHANGES IN SCHEDULED
IN-SERVICE DATES OF COAL-FIRED GENERATING UNITS 1/
(1980-1989)

Slippage (Months)	300 Mw or Larger			Less Than 300 Mw		
	No. of Units	Mw	Megawatt-Months (Mw x Months)	No. of Units	Mw	Megawatt-Months (Mw x Months)
48	1	620	29,760	-	-	-
36-47	5	3,420	107,028 2/	-	-	-
24-35	13	7,893	201,992	2	500	12,000
12-23	36	20,579	272,298	3	463	5,756
1-11	24	12,980	60,127	6	1,427	3,669
Total	79	45,492	671,205	11	2,390	21,425
Advancement (Months)						
12-18	3	1,400	23,100	1	280	3,360
1-11	4	2,764	11,594	2	350	3,050
Total	7	4,164	34,694	3	630	6,410
Net Slippage	72	41,328	636,511	8	1,760	15,015

1/ Comparison of scheduled in-service dates in the April 1, 1979
and April 1, 1980 Regional Reliability Council Reports.

2/ 18,792 megawatt-months excluded for period after December 31, 1989.

Table X.2

COAL-FIRED GENERATING UNITS 300 MW OR LARGER
 FOR WHICH ORIGINALLY SCHEDULED IN-SERVICE DATES (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/79)
 HAVE BEEN MODIFIED (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/80)

DOE/ERA Electric Region	Generating Unit	Utility	Net Expected Capability (Mw)	In-Service Date		Schedule Change		
				4/1/79 Report	4/1/80 Report	Months	Megawatt-Months (Mw x Months)	Net For Region
1	Pleasants No. 2	Allegheny Power System, Inc.	626	3/80	10/80	7	4,382	
1	Lower Armstrong No. 1	Allegheny Power System, Inc.	630	5/84	9/86	28	17,640	
1	Lower Armstrong No. 2	Allegheny Power System, Inc.	630	3/85	9/87	30	18,900	
1	Lower Armstrong No. 3	Allegheny Power System, Inc.	630	3/86	9/88	30	18,900	59,822
2	Lewis Co. No. 2	American Electric Power Co., Inc.	1,300	12/88	6/88	(6)	(7,800)	(7,800)
3	Sears Island	Central Maine Power Company	568	11/87	11/89	24	13,632	13,632
5	Brandon Shores No. 1	Baltimore Gas & Electric Co.	620	1/82	5/84	28	17,360	
5	Brandon Shores No. 2	Baltimore Gas & Electric Co.	620	1/84	1/88	48	29,760	
5	Seward No. 7	GPU: Pennsylvania Electric Co.	625	12/85	5/87	17	10,625	
5	Dickerson No. 4	Potomac Electric Power Co.	400	1/87	5/87	4	1,600	
5	Coho No. 1	GPU: Pennsylvania Electric Co.	625	5/88	5/89	12	7,500	66,845
7	McIntosh No. 3	City of Lakeland (FL)	334	11/81	10/81	(1)	(334)	
7	Crystal River No. 5	Florida Power Corporation	670	5/84	6/84	1	670	
7	Fossil Coal No. 1	Florida Power Corporation	668	10/85	6/86	8	5,344	
7	Unknown No. 1	City of Lakeland (FL)	350	5/87	5/86	(12)	(4,200)	
7	Coal A No. 1	Florida Power & Light Co.	600	6/87 1/	12/85	(18)	(10,800)	(9,320)
9	Miller No. 2	So. Co.: Alabama Power Co.	654	6/82	6/83	12	7,848	
9	Miller No. 3	So. Co.: Alabama Power Co.	654	6/83	6/85	24	15,696	
9	Miller No. 4	So. Co.: Alabama Power Co.	654	6/84	6/87	36	23,544	
9	Scherer No. 3	So. Co.: Georgia Power Co.	808	2/85	2/87	24	19,392	
9	Scherer No. 4	So. Co.: Georgia Power Co.	808	2/87	2/89	24	19,392	
9	Unsite - Site A No. 1	So. Co.: Alabama Power Co.	783	6/87	6/90	36	28,188	
9	Unsite - Site A No. 2	So. Co.: Alabama Power Co.	783	6/88	6/91	36	28,188	142,248
10	Rodemacher No. 2	Central Louisiana Electric Co., Inc.	530	3/82	1/82	(2)	(1,060)	
10	R. S. Nelson No. 5	Gulf States Utilities Company	540	3/84	4/85	13	7,020	
10	Lovelady No. 1	Gulf States Utilities Company	400	9/85	10/86	13	5,200	
10	Lovelady No. 2	Gulf States Utilities Company	400	9/87	10/87	1	400	11,560

X.5

Table X.2

COAL-FIRED GENERATING UNITS 300 MW OR LARGER
FOR WHICH ORIGINALLY SCHEDULED IN-SERVICE DATES (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/79)
HAVE BEEN MODIFIED (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/80)

DOE/ERA Electric Region	Generating Unit	Utility	Net Expected Capability (Mw)	In-Service Date		Schedule Change		
				4/1/79 Report	4/1/80 Report	Months	Megawatt-Months (Mw x Months)	Net For Region
12	Roxboro No. 4	Carolina Power & Light Company	720	3/80	9/80	6	4,320	
12	Mayo No. 1	Carolina Power & Light Company	720	3/82	3/83	12	8,640	
12	Cross Site No. 1	South Carolina Public Service Authority	450	5/83	11/86	42	18,900	
12	Cross Site No. 2	South Carolina Public Service Authority	450	5/85	11/83	(18)	(8,100)	
12	Unsite Coal No. 1	South Carolina Electric & Gas Co.	500	5/85	5/87	24	12,000	
12	Cross Site No. 3	South Carolina Public Service Authority	450	5/87	11/88	18	8,100	
12	Unsite Coal No. 2	South Carolina Electric & Gas Co.	500	5/87	5/89	24	12,000	55,860
14	East Bend No. 1	Cincinnati Gas & Electric Co.	600	10/84	10/85	12	7,200	
14	Killen Station No. 1	Dayton Power & Light Company	600	4/86	12/85	(4)	(2,400)	
14	East Bend No. 3	Cincinnati Gas & Electric Co.	600	4/88	10/89	18	10,800	15,600
15	D. B. Wilson No. 1	Big Rivers Electric Corp.	395	6/84	7/84	1	395	
15	Hancock Co. No. 1	Kentucky Utilities Company	650	10/85	10/87	24	15,600	
15	Trimble County No. 2	Louisville Gas & Electric Co.	495	6/86	6/88	24	11,880	27,875
16	Merom No. 2	Hoosier Energy Div. (IN) Coop.	500	6/81	10/81	4	2,000	
16	Merom No. 1	Hoosier Energy Div. (IN) Coop.	500	4/82	7/82	3	1,500	
16	Petersburg No. 4	Indianapolis Power & Light Co.	515	10/83	10/84	12	6,180	
16	A. B. Brown No. 3	Southern Indiana Gas & Electric Co.	500	4/86	1/88	21	10,500	
16	Patriot No. 1	Indianapolis Power & Light Co.	650	10/87	10/88	12	7,800	27,980
17	Newton No. 2	Central Illinois Public Service Co.	575	12/81	12/82	12	6,900	
17	Duck Creek No. 2	Central Illinois Light Co.	400	3/84	3/86	24	9,600	16,500
19	Pleasant Prairie No. 2	Wisconsin Electric Power Co.	580	4/82	4/83	12	6,960	
19	Edgewater No. 5	Wisconsin Power & Light Co.	400	6/83	3/84	9	3,600	10,560

Table X.2

COAL-FIRED GENERATING UNITS 300 MW OR LARGER
FOR WHICH ORIGINALLY SCHEDULED IN-SERVICE DATES (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/79)
HAVE BEEN MODIFIED (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/80)

DOE/ERA Electric Region	Generating Unit	Utility	Net Expected Capability (Mw)	In-Service Date		Schedule Change		Net For Region
				4/1/79 Report	4/1/80 Report	Months	Megawatt-Months (Mw x Months)	
20	Laramie River No. 2	City of Lincoln (NE)	500	10/80	4/81	6	3,000	
20	Gentleman No. 2	Nebraska Public Power District	600	5/81	11/81	6	3,600	
20	Louisa	Iowa-Illinois Gas & Electric Co.	650	1/83	7/83	6	3,900	
20	Colstrip No. 3	Montana Power Company	70 <u>2/</u>	7/83	1/84	6	420	
20	Colstrip No. 4	Montana Power Company	70 <u>2/</u>	5/84	11/84	6	420	
20	Sherburne County No. 3	Northern States Power Co. (MN)	800	5/84	5/85	12	9,600	
20	Fossil No. 3	Nebraska Public Power District	600	5/86	5/87	12	7,200	28,140
21	Jeffrey Energy Ctr. No. 3	Kansas Power & Light Co.	680	6/82	6/83	12	8,160	
21	Jeffrey Energy Ctr. No. 4	Kansas Power & Light Co.	680	6/84	6/85	12	8,160	
21	Iatan No. 2	Kansas City Power & Light Co.	650 <u>3/</u>	3/88	6/89	15	9,750	26,070
22	Sooner No. 2	Oklahoma Gas & Electric Co.	515	6/80	10/80	4	2,060	
22	Northeastern No. 4	Cen. & Sw.: Public Service Co. of Oklahoma	450	6/80	9/80	3	1,350	
22	Hugo No. 1	Western Farmers Electric Coop. (OK)	376	4/81	3/82	11	4,136	
22	Muskogee No. 6	Oklahoma Gas & Electric Co.	515	6/83 <u>1/</u>	11/84	17	8,755	
22	Pirkey No. 1	Cen. & Sw.: Southwestern Electric Pwr. Co.	640	3/84	3/85	12	7,680	
22	Unsite'd Coal No. 1	Oklahoma Gas & Electric Co.	500	6/86 <u>1/</u>	6/87 <u>1/</u>	12	6,000	
22	Unsite'd Coal No. 2	Oklahoma Gas & Electric Co.	500	6/87 <u>1/</u>	6/88 <u>1/</u>	12	6,000	
22	Coaleto Creek No. 2	Cen. & Sw.: Central Power & Light Co.	325 <u>4/</u>	1/88	1/89	12	3,900	39,881
23	W. A. Parish No. 8	Houston Lighting & Power Co.	540	12/82	5/83	5	2,700	
23	Twin Oak No. 1	Texas Util.: Texas Power & Light Co.	750	1/84	2/85	13	9,750	
23	Forest Grove No. 1	Texas Utilities Company System	750	1/84	1/87	36	27,000	
23	Martin Lake No. 4	Texas Utilities Company System	750	1/85	2/85	1	750	
23	Twin Oak No. 2	Texas Util.: Texas Power & Light Co.	750	1/86	2/86	1	750	
23	F. P. P. No. 3 <u>5/</u>	Lower Colorado River Authority	400	4/86	6/87	14	5,600	
23	Unsite'd No. 1	Texas Utilities Company System	750	1/87	1/88	12	9,000	
23	Coaleto Creek No. 2	Cen. & Sw.: Central Power & Light Co.	315 <u>4/</u>	1/88	1/89	12	3,780	
23	Unsite'd No. 1	San Antonio Public Service Board	500	4/88	4/89	12	6,000	65,330

X.7

Table X.2

COAL-FIRED GENERATING UNITS 300 MW OR LARGER
FOR WHICH ORIGINALLY SCHEDULED IN-SERVICE DATES (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/79)
HAVE BEEN MODIFIED (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/80)

DOE/ERA Electric Region	Generating Unit	Utility	Net Expected Capability (Mw)	In-Service Date		Months	Schedule Change	
				4/1/79 Report	4/1/80 Report		Mayawatt-Months (Mw x Months)	Net For Region
24	Pawnee No. 1	Public Service Co. of Colorado	470	7/80	1/81	6	2,820	
24	Southeast No. 1	Public Service Co. of Colorado	470	4/84	4/85	12	5,640	
24	Southeast No. 2	Public Service Co. of Colorado	470	4/85	7/86	15	7,050	15,510
25	Colstrip No. 3	Montana Power Company	630 2/	7/83	1/84	6	3,780	
25	Colstrip No. 4	Montana Power Company	630 2/	5/84	11/84	6	3,780	7,560
26	Coronado No. 2	Salt River Proj. Agri. Imp. Pwr. Dist.	245 6/	4/80	10/80	6	1,470	
26	Springerville No. 1	Tucson Gas & Electric Company	350	5/85	6/85	1	350	1,820
27	Coronado No. 2	Salt River Proj. Agri. Imp. Pwr. Dist.	105 6/	4/80	10/80	6	630	
27	H. Allen No. 1	Nevada Power Company	270 7/	6/85	6/86	12	3,240	
27	H. Allen No. 2	Nevada Power Company	270 7/	6/86	6/87	12	3,240	
27	H. Allen No. 3	Nevada Power Company	270 7/	6/87	6/88	12	3,240	
27	California Coal No. 1	Southern California Edison Co.	456 8/	6/87	9/88	15	6,840	
27	H. Allen No. 4	Nevada Power Company	270 7/	6/88	6/89	12	3,240	
27	California Coal No. 2	Southern California Edison Co.	456 8/	6/88	9/89	15	6,840	27,270
28	H. Allen No. 1	Nevada Power Company	230 7/	6/85	6/86	12	2,760	
28	H. Allen No. 2	Nevada Power Company	230 7/	6/86	6/87	12	2,760	
28	H. Allen No. 3	Nevada Power Company	230 7/	6/87	6/88	12	2,760	
28	California Coal No. 1	Southern California Edison Co.	44 8/	6/87	9/88	15	660	
28	H. Allen No. 4	Nevada Power Company	230 7/	6/88	6/89	12	2,760	
28	California Coal No. 2	Southern California Edison Co.	44 8/	6/88	9/89	15	660	12,360

X
8

- 1/ Month was not reported, DOE arbitrarily used 6.
2/ Total net expected capability is 700 Mw; 70 in region 20 and 630 in region 25.
3/ Total net expected capability is 650 Mw; of the 650 Mw, 79 is unassigned; for purposes here, DOE includes it in region 21.
4/ Total net expected capability is 640 Mw; 325 in region 22 and 315 in region 23.
5/ Formerly Seymour No. 3.
6/ Total net expected capability is 350 Mw; 245 in region 26 and 105 in region 27.
7/ Total net expected capability is 500 Mw; 270 in region 27 and 230 in region 28.
8/ Total net expected capability is 500 Mw; 456 in region 27 and 44 in region 28.
() Indicates negative number.

Table X.3

COAL-FIRED GENERATING UNITS LESS THAN 300 MW
FOR WHICH ORIGINALLY SCHEDULED IN-SERVICE DATES (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/79)
HAVE BEEN MODIFIED (REGIONAL RELIABILITY COUNCIL REPORTS, 4/1/80)

DOE/ERA Electric Region	Generating Unit	Utility	Net Expected Capability (Mw)	In-Service Date		Schedule Change		
				4/1/79 Report	4/1/80 Report	Months	Megawatt-Months (Mw x Months)	Net For Region
7	Deerhaven No. 2	Gainesville-Alachua County (FL)	235	1/81	2/81	1	235	235
9	Effingham Station No. 2	Savannah Electric & Power Co.	163	3/86	3/87	12	1,956	1,956
12	Winyah No. 4	South Carolina Public Service Authority	280	5/82	5/81	(12)	(3,360)	(3,360)
16	A. B. Brown No. 2	Southern Indiana Gas & Electric Co.	250	4/83	1/84	9	2,250	2,250
20	Osage No. 4	Black Hills Power & Light Co. (SD)	100	6/85	10/84	(8)	(800)	
20	Fossil No. 1	Montana-Dakota Utilities Co.	100	5/86	5/87	12	1,200	400
21	Holcomb No. 1	Sunflower Electric Coop. (KS)	280	5/83	6/83	1	280	280
24	Rawhide No. 1	Platte River Power Authority	250	1/85	4/84	(9)	(2,250)	
24	Ray D. Nixon No. 2	City of Colorado Springs	200	11/86	12/87	13	2,600	350
26	Cholla No. 3	Arizona Public Service Company	242	6/80	8/80	2	484	
26	Escalante No. 1	Plains Electric Gen. & Trans. Coop., Inc.	210	5/84	6/84	1	210	
26	Escalante No. 2	Plains Electric Gen. & Trans. Coop., Inc.	210	5/88	6/88	1	210	904
27	Warner Valley No. 1	Nevada Power Company	125 1/	6/83	6/85	24	3,000	
27	Warner Valley No. 2	Nevada Power Company	125 1/	6/84	6/86	24	3,000	6,000
28	Warner Valley No. 1	Nevada Power Company	62.5 1/	6/83	6/85	24	1,500	
28	Warner Valley No. 2	Nevada Power Company	62.5 1/	6/84	6/86	24	1,500	3,000
30	Warner Valley No. 1	Nevada Power Company	62.5 1/	6/83	6/85	24	1,500	
30	Warner Valley No. 2	Nevada Power Company	62.5 1/	6/84	6/86	24	1,500	3,000

1/ Total net expected capability is 250 Mw; 125 in region 27, 62.5 in region 28, and 62.5 in region 30.

() Indicates negative number.

Table X.4

TEN COAL-FIRED GENERATING UNITS
WITH LARGE OIL DISPLACEMENT POTENTIAL
(THROUGH 1989)

<u>Generating Unit</u>	<u>Presently Expected In-Service Date</u>	<u>Net Expected Capability (Mw)</u>	<u>Electric Region</u>	<u>Oil Displaced 1/ (Total Bbls) (Bbls/Day)</u>	
Brandon Shores No. 2	1/88	620	5	18,887,005	12,901
Brandon Shores No. 1	5/84	620	5	11,017,420	12,901
Sears Island	11/89	568	3	10,178,196	13,905
Seward No. 7	5/87	625	5	6,743,093	13,005
California Coal No. 1	9/88	500	27,28	5,599,800	12,240
California Coal No. 2	9/89	500	27,28	5,599,800	12,240
Coho No. 1	5/89	625	5	4,759,830	13,005
H. Allen No. 1	6/86	500	27,28	4,479,840	12,240
H. Allen No. 2	6/87	500	27,28	4,479,840	12,240
H. Allen No. 3	6/88	500	27,28	4,479,840	12,240
Total		5,558		76,224,664	126,917

1/ The use of this oil could be avoided if the completion schedules reported in the April 1, 1979 Regional Reliability Council reports are followed.

Table X.5

TEN COAL-FIRED GENERATING UNITS
WITH LARGE GAS DISPLACEMENT POTENTIAL
(THROUGH 1989)

<u>Generating Unit</u>	<u>Presently Expected In-Service Date</u>	<u>Net Expected Capability (Mw)</u>	<u>Electric Region</u>	<u>Gas Displaced 1/</u>	
				<u>(Total Mcf)</u>	<u>(Mcf/Day)</u>
Forest Grove No. 1	1/87	750	23	99,610,560	90,720
Twin Oak No. 1	2/85	750	23	35,970,480	90,720
Unsited No. 1	1/88	750	23	33,203,520	90,720
R. S. Nelson No. 5	4/85	540	10	24,280,074	61,236
Coleta Creek No. 2	1/89	640	22,23	24,736,622	67,586
Muskogee No. 6	11/84	515	22	24,224,735	46,721
Unsited No. 1	4/89	500	23	22,135,680	60,480
Pirkey No. 1	3/85	640	22	21,250,253	58,061
F. P. P. No. 3	6/87	400	23	20,659,968	48,384
Lovelady No. 1	10/86	400	10	17,985,240	45,360
Total		5,885		324,057,132	659,988

1/ The use of this gas could be avoided if the completion schedules reported in the April 1, 1979 Regional Reliability Council reports are followed.

GLOSSARY

The purpose of this glossary is to define for the purposes of this report those terms which may be unfamiliar, or whose meaning may not be clear, to non-technical readers. It is not intended that this glossary replace technical dictionaries.

AVAILABILITY FACTOR

- the ratio of the time a machine or equipment is ready for or in service, to the total time interval under consideration. "Total time interval" refers to calendar time and is not affected by a unit being in service or not.

CAPABILITY

- a general term for the maximum load which a generating unit, power plant or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress. When used in reference to a system or plant, capability includes all generating units and is known as "installed capability". It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage or other reasons, or only operable at less than full output.

Summer not dependable planned capability refers to the capability during the summer peak period. This period usually occurs on most systems between June 1 and September 30; it may last for several days. It is expected that the unit, plant or system will be able to supply the stated power output for the duration of the peak period.

Winter net dependable planned capability refers to the capability during the winter peak period. This period occurs on most systems between December 1 of any year and March 31 of the following year. It is expected that the unit, plant or system will be able to supply the stated power output for the duration of the peak period. Steam units and combustion turbines may have capabilities greater in winter than in summer, in those locations where the ambient temperature is significantly lower in winter than in summer.

CAPACITY

- the load for which a generating unit is rated. That is, the load which a unit has been designed to supply under strictly specified conditions relating to height above sea level, ambient temperature, cooling water temperature, fuel type and characteristics, condition of heat transfer surfaces, power factor, duration and constancy of the load to be carried and possibly other factors. This is a nominal value that may not correspond exactly to "capability". In general discussions of the ability of a system to supply electric power, "capacity" and "capability" are frequently used interchangeably. The magnitude of the difference between "capability" and "capacity" is usually not great.

CAPACITY (INOPERABLE)

- capacity which could not be operated for the period specified because of lack of fuel, lack of personnel, because it is in deactivated shut-down status or for similar reasons. This category does not include forced or scheduled outages.

CAPACITY FACTOR

- the ratio of the average demand on a machine or equipment for the period of time considered, to the capacity rating of the machine or equipment. The meaning can be extended to a plant or a system.

DEMAND

- the rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, expressed in kilowatts or other suitable unit, at a given instant or averaged over any designated period of time.

Coincident Demand--any demand that occurs simultaneously with any other demand; also the sum of any set of coincident demands.

Instantaneous Demand--the demand at any instant, usually determined from the reading of an indicating or recording instrument.

Integrated Demand--the demand averaged over a specified period, usually determined by an integrating demand meter or by the integration of a load curve.

Peak Demand--the greatest of a particular type of demand occurring within a specified period.

Noncoincident Demand--the sum of the individual maximum demands regardless of time of occurrence within a specified period, usually not more than 1 year.

DEMAND INTERVAL

- the period of time during which the electric energy flow is averaged in determining demand, such as 60-minute, 3p-minute, or instantaneous.

DISTRIBUTION SYSTEM

- that portion of an electric system used to deliver electric energy from points on the transmission or bulk power system to the consumers.

DIVERSITY FACTOR

- the ratio of the sum of the noncoincident maximum demands of the various subdivisions of a system, or part of a system, to the maximum coincident demand of the whole system, or part under consideration.

DIVERSITY, LOAD

- the difference between the peak of coincident and noncoincident demands of two or more individual loads.

Seasonal Diversity--load diversity between two (or more) electric systems which occurs when their annual peaks are in different seasons of the year.

Time Zone Diversity--load diversity between electric systems in different time zones resulting from the time difference as it affects the demands for power.

ELECTRIC REGION

- A subarea of a Reliability Council area. The 29 Electric Regions in the Contiguous U.S. (plus one for Alaska) were established by ERA for the purposes of the Fuel Use Act and have proven useful for analyses of electric power supply adequacy and reliability.

ELECTRIC SYSTEM

- physically connected electric generating, transmission, and distribution facilities operated to provide electricity to customers. The facilities need not be all

under control of a single organization, as the term is used in this report. Thus, for the purposes of this report the Detroit Edison Company is a system, Consumers Power Company is a system and the two together comprise a system. The term "utility" or "electric utility" is used in this report to describe a system under single control, whether privately-owned, publicly-owned or cooperatively-owned. Thus, the Los Angeles Department of Water and Power, a municipal organization, is an electric utility, as are the Tennessee Valley Authority, the Power Authority of the State of New York and the Louisville Gas & Electric Company, for example. The Tri-State G. & T. Association, Inc., is also a system and an electric utility in the sense that those terms are used in this report.

ENERGY

- that which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours or megawatt hours.

Economy Energy--electric energy produced from a source in one system and substituted for energy that would otherwise have been produced by a less economical source in another system.

Interchange Energy--electric energy received by one electric utility system in exchange for energy delivered to the other system at another time or place. Interchange is to be distinguished from a direct purchase or sale, although energy balances accumulated under interchange agreements are sometimes settled for in cash.

Net Energy For System--the electric energy requirements of a system, including losses, defined as: (1) net generation of the system, plus (2) energy received from others, less (3) energy delivered to other systems for resale.

Off-Peak Energy--electric energy supplied during periods of relatively low system demands as specified by the supplier.

On-Peak Energy--electric energy supplied during periods of relatively high system demands as specified by the supplier.

LOAD

- the amount of electric power demanded at a given point or from a given system.

Base Load--the minimum load in a stated period of time.

Connected Load--the sum of the ratings of the electric power consuming apparatus connected to the system, or part of the system, under consideration.

Interruptible Load--electric load which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement.

Peak Load--the maximum load in a stated period of time.

Plant Factor--the ratio of the average demand on a power plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

LOSS

Electric System Loss--total electric energy loss in the electric system. It consists of transmission, transformation, and distribution losses, and unaccounted-for-energy-losses between sources of supply and points of delivery.

Energy Loss--the difference between energy input and output as a result of transfer of energy between two points.

Line Loss--energy loss and power loss on a transmission or distribution line.

No-Load-Loss--power and energy losses in an electric system, or portion thereof, when energized at rated voltage and frequency, but not supplying load.

NETWORK

- a system of transmission or distribution lines so connected and operated as to permit multiple power supply to any principal point on it.

NUCLEAR REACTOR

- an apparatus by means of which a fission chain reaction can be initiated, maintained, and controlled. Its essential component is a core with fissionable fuel. It usually has a moderator, reflectors, shielding, and control mechanisms.

OUTAGE

- the out-of-service condition of a generating unit, transmission line, or other facility.

Forced Outage--the shutdown of a generating unit, transmission line, or other facility, for emergency reasons. The nature of the emergency is such that the shutdown must be effected immediately or not later than the very next weekend.

Scheduled Outage (maintenance)--the shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule. The shutdown may be postponable within certain limits.

HEAT RATE

- a measure of generating station thermal efficiency, generally expressed as BTU per net kilowatt-hour. It is computed by dividing the total BTU content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.

INTERCONNECTION

- a transmission line, transformer or other device or equipment permitting a flow of energy between the facilities of two electric systems.

Emergency Interconnection--an interconnection established to meet an emergency need.

INTERTIE--same as INTERCONNECTION.

GENERATING UNIT

- an electric generation together with its prime mover.

GENERATION

- the act or process of producing electric energy from other forms of energy; also the amount of electric energy so produced.

Gross Generation--the total amount of electric energy produced by a generating station or stations, measured at the generator terminals.

Net Generation--gross generation less plant use.

Nonutility Generation--generation by producers having generating plants for the purpose of supplying electric power required by their own industrial, commercial, or military operations.

Utility Generation--generation by electric systems engaged in the business of selling or supplying electric energy for use by the general public.

POWER

- the time rate of transferring energy. The term is frequently used in a broad sense, as a commodity of capacity and energy, having only general association with the scientific meaning.

Electric Power--a term used in the electric power industry to mean inclusively power and energy.

Interruptible Power--power made available under agreements which permit curtailment or cessation of delivery by the supplier under conditions specified in the agreement.

POWER PLANT

- A location at which one or more generating units are located.

Base Load Plant--a power plant which is normally operated to provide base load and which, consequently, operates at essentially a constant load.

Fossil-Fuel Plant--an electric power plant utilizing fossil fuel, such as coal, lignite, oil or natural gas, as its source of energy.

Hydroelectric Plant--an electric power plant utilizing falling water for the motive force of its prime movers.

Nuclear Power Plant--an electric generating station utilizing the energy from a nuclear reactor as the source of power.

Peak Load Plant--a power plant which is normally operated to provide power during maximum load periods.

Power Plant (Generating Station)--a generating station at which are located prime movers, electric generators, and auxiliary equipment for producing electric energy.

Pumped Storage Plant--a power plant utilizing an arrangement whereby electric energy is generated for peak load use, by utilizing water pumped into an elevated storage reservoir usually during off-peak periods.

Run-of-River Plant--a hydroelectric power plant utilizing the flow of the stream as it occurs.

Steam-Electric Plant--an electric power plant utilizing steam for the motive force of its prime movers.

RESERVE MARGIN

- as used in this report, "Reserve Margin" is the difference between system capability at the time of peak demand and the system peak demand. When this difference is expressed as a percentage of the peak demand, the margin is called "Percent Reserve". The summer reserve margin and the winter reserve margin usually are different. When "Reserve Margin" or "Percent Reserve" are used without being qualified, the reference is to "Installed Reserve" (also called "Planned Reserve" in this report), meaning the difference between the sum of the capabilities of all units on the system, including those temporarily inoperable, and the system peak demand.

RESERVE (OPERATING)

- generating capacity (or capability) that can be made available to take load within a short time. The time limitation is usually stated to be "ten minutes or less" but in some instances may be as much as one-half hour. "Operating Reserve" consists of "Spinning Reserve" and "Non-Spinning Reserve". The Spinning Reserve, as defined above, is in operation and is connected to the bus. The Non-Spinning Reserve is capability that can be started, connected to the bus and loaded within the specified time limitation.

RESERVE (SPINNING)

- generating capacity (or capability) connected to the bus and ready to take load. This includes the capability of units running unloaded and the capability available in units that are loaded to less than their capability and which can be loaded further.

RESERVE (PLANNED)

- the reserve which is planned for a given peak load period. It includes allowances for all foreseeable contingencies affecting capacity.

RESERVE (ACTUAL)

- the actual reserve at time of peak demand after deduction of all foreseeable capacity contingencies.

RESERVE (COLD)

- generating capability that requires several hours, or possibly a day, to bring into operation.

RESERVE (DE-ACTIVATED)

- generating capability which will take several weeks at best to become operable. This is capability that a system does not expect to operate under normal conditions because it is obsolescent, inefficient, may violate environmental quality restrictions, may require extensive maintenance, may require fuel not readily available, or for other reasons.

RESERVE (AVAILABLE)

- this is a term that has been developed in the course of preparation of this report, intended to take into account the effect of scheduled maintenance and probable forced outages on installed capability. It is the installed (planned) reserve margin less the capability that is inoperable because of forced outages, maintenance work or other reasons, plus the net of imports less exports, at the time of system peak (summer or winter) demand. "Available Reserve" is intended to be the difference between system capability actually available to meet peak demand, and peak demand.

WATER CONDITIONS

- Adverse Water Conditions--water conditions which limit the output of hydroelectric generating units because of insufficient water supply or reduced head. Insufficient water supply may be due to low precipitation, diversion of water for purposes other than power production or other reasons. The availability of water under adverse conditions is usually determined from analysis of historical studies extending over a long period of years. Adverse conditions may also result from reduced net head caused by high water on the downstream side of a plant.
- Average Water Conditions--conditions of precipitation and runoff which provide water for hydroelectric plants approximating the average amount and distribution available over a long time period, usually the period of record.

THERMAL

- a term used to identify a type of electric generating station or power plant, or the capacity or capability thereof, in which the source of energy for the prime mover is heat. The heat may be obtained from combustion of coal, oil, gas, waste or other material, from geothermal sources (heat from the earth's core) or from nuclear fission or other nuclear process. Heat for electric generation may also be obtained from solar radiation, but generation using that source is usually referred to as one of the types of "solar energy".

TRANSMISSION

- the movement or transfer of electric energy in bulk. Ordinarily the transmission movement is considered to end when the voltage level of the energy is transformed for distribution to ultimate consumers. The term is also used to refer to the aggregate of system transmission facilities.

Transmission Line Capacity--the maximum continuous rating of a transmission line. The rating may be limited by thermal considerations, capacity of associated equipment, voltage regulation, system stability or other factors.

Transmission System--an interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points at which it is transformed for delivery to ultimate consumers, or is delivered to electric systems of others.

The Reliability Councils

The Regional Electric Reliability Councils were established during the period 1963 through 1969, first as twelve groups and ultimately, through consolidation, to the present nine. Each Council is a voluntary association of electric utilities in a geographic area of the United States defined mainly by historic operating practices and patterns of interconnection growth. The nine Councils together, covering the contiguous United States, comprise the National Electric Reliability Council (NERC).

The Regional Councils and the National Council are industry organizations, with no connection to the Federal, State or local governments. All operations of the Councils are financed by assessments on the utility members.

Annually on April 1 each Regional Council provides a report to the Economic Regulatory Commission (ERA) summarizing the coordinated plans and forecasts of the regional utilities for a ten-year advance period, with additional load and capacity forecasts for a further ten-year period. The National Council usually publishes a summary and review of the nine Regional Council reports.

A detailed review of the history, structure and functions of the Reliability Councils is provided in Appendix A of the ERA report "Electric Power Supply and Demand 1979-1988 for the Contiguous United States", published December 1979.

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

APPENDIX B

Utilities Included In This Report

The Reliability Council member utilities, and other utilities for which data have been included in this report, are tabulated on the following pages. The lists have been produced from the April 1, 1980, Coordinated Bulk Power Supply Programs of the nine Regional Reliability Councils.

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
(ECAR)

Bulk Power membership currently consists of 26 companies (19 systems) as follows:

Appalachian Power Company (AEP)
Cincinnati Gas & Electric Company
Cleveland Electric Illuminating Company
Columbus and Southern Ohio Electric Company
Consumers Power Company
Dayton Power and Light Company
Detroit Edison Company
Duquesne Light Company
East Kentucky Power Cooperative
Indiana & Michigan Electric Company (AEP)
Indiana-Kentucky Electric Corporation (OVEC)
Indianapolis Power & Light Company
Kentucky Power Company (AEP)
Kentucky Utilities Company
Louisville Gas and Electric Company
Monongahela Power Company (APS)
Northern Indiana Public Service Company
Ohio Edison Company
Ohio Power Company (AEP)
Ohio Valley Electric Corporation
Pennsylvania Power Company (OE)
Potomac Edison Company (APS)
Public Service Indiana
Southern Indiana Gas and Electric Company
Toledo Edison Company
West Penn Power Company (APS)

The ECAR Liaison System membership currently consists of the following systems:

Big Rivers Electric Corporation
Buckeye Power, Incorporated
City of Cleveland - Division of Light and Power
City of Detroit - Public Lighting Department
Edison Sault Electric Company
Hamilton Department of Public Utilities - Electric Div.
Henderson Municipal Power & Light
Hoosier Energy Division of Indiana Statewide REC, Inc.
Lansing Board of Water and Light

Michigan Municipal Cooperative Pool
Conalco
Grand Haven Board of Light & Power
Hart Hydro Electric
Lowell Light & Power
Northern Michigan Electric Coop., Inc.
Traverse City Light & Power Department
Wolverine Electric Cooperative
Zeeland Board of Public Works
Owensboro Municipal Utilities
Richmond Power and Light
Wabash Valley Power Association

ELECTRIC RELIABILITY COUNCIL OF TEXAS
(ERCOT)

City of Austin Electric Utilities
City of Brownsville
Central Power & Light Company
Dallas Power & Light Company
Houston Lighting & Power Company
Lower Colorado River Authority
City of San Antonio Public Service

South Texas and Medina Electric Cooperative, Pool
South Texas Electric Cooperative, Inc.
Medina Electric Cooperative, Inc.

Texas Electric Service Company
Texas Power & Light Company
Texas Utilities Company System, Comprising
Dallas Power & Light Co., Texas Power & Light Co.
and Texas Electric Service Co.

Texas Municipal Power Pool
City of Bryan
Brazos Electric Power Cooperative, Inc.
City of Denton
City of Garland
City of Greenville

West Texas Utilities Company

MID-ATLANTIC AREA COUNCIL
(MAAC)

PJM

Atlantic City Electric Company
Baltimore Gas and Electric Company
Delmarva Power & Light Company
*Jersey Central Power & Light Company
*Metropolitan Edison Company
*Pennsylvania Electric Company
Pennsylvania Power and Light Company
Philadelphia Electric Company
Potomac Electric Power Company
Public Service Electric & Gas Company
UGI Corporation

Associates

Allegheny Electric Cooperative
representing the Pennsylvania and
New Jersey Cooperatives

The Easton Utilities Commission
representing the Maryland Municipals

The City of Vineland Electric Utility
representing the New Jersey Municipals

The City of Dover representing the
Delaware Municipals

*Subsidiaries of the General Public Utilities Corporation

THE MID-AMERICA INTERPOOL NETWORK (MAIN) ORGANIZATION

The Mid-America Interpool Network (MAIN) was formally organized in November 1964 to promote maximum coordination of planning, construction, and utilization of generation and transmission facilities of its members in order to improve the reliability of electric bulk power supply in the Middle West.

Regular membership is open to any power supplier who has a high capacity interconnection (115 kV or above) with a regular member and whose operations have a significant effect on the reliability of the interconnected system of the region. MAIN's regular membership is presently composed of investor-owned, rural cooperative and municipal power suppliers. The members are arranged in geographical groups to expedite operation of the council. The regular members and the group assignments are:

<u>Groups</u>	<u>Members</u>
Commonwealth Edison	Commonwealth Edison Company
Illinois Group	Central Illinois Light Company Central Illinois Public Service Company* Illinois Power Company* City Water, Light & Power, Springfield, IL Southern Illinois Power Cooperative
Missouri Group	Associated Electric Cooperative, Inc. Union Electric Company*
Wisconsin-Upper Michigan Systems (WUMS) Group	Madison Gas and Electric Company Wisconsin Electric Power Company System Wisconsin Power and Light Company Wisconsin Public Service Corporation Upper Peninsula Power Company

*Illinois-Missouri Pool

Associate membership is open to municipal or other small electric systems operating in the MAIN region, but not eligible for regular membership because their operations do not have a significant effect on the reliability of the interconnected system of the region. The associate members are:

<u>Groups</u>	<u>Associate Members</u>
Illinois Group	Association of Illinois Electric Cooperatives Western Illinois Power Cooperative, Inc. Soyland Power Cooperative
Wisconsin-Upper Michigan Systems (WUMS) Group	Municipal Electric Utilities of Wisconsin

POWER SUPPLIERS INCLUDED IN REPORT

This report includes information for member systems of MAIN and for other systems in the MAIN region with generation of 25 MW or more. Some non-member systems meeting this limitation did not submit information.

Associated Electric Cooperative has membership in both MAIN and the Southwest Power Pool (SPP); agreement has been reached for Associated to report through MAIN. 1/

The power suppliers included in this report are:

Illinois

Central Illinois Light Company
Central Illinois Public Service Company
City Water, Light & Power, Springfield
Commonwealth Edison Company
Illinois Power Company
Southern Illinois Power Cooperative
Western Illinois Power Cooperative, Inc.
Soyland Power Cooperative
Village of Winnetka
Rochelle Municipal Utilities

Missouri

Associated Electric Cooperative, Inc.
City of Columbia, Missouri
Union Electric Company

Wisconsin-Upper Michigan

Madison Gas & Electric Company
Upper Peninsula Power Company
Wisconsin Electric Power Company System
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
Kaukauna-Menasha Interconnected Systems
City of Manitowoc
City of Marquette
City of Marshfield

1/ As of June 1, 1980, Associated will drop its membership in MAIN and will report through Southwest Power Pool.

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT
(MARCA)

MID-CONTINENT AREA POWER POOL (MAPP) MEMBERS

Easin Electric Power Cooperative
Cooperative Power Association
Dairyland Power Cooperative
Eastern Iowa Light and Power Cooperative
Heartland Consumers Power District
Interstate Power Company
Iowa Electric Light and Power Cooperative
 Central Iowa Power Cooperative
Iowa-Illinois Gas and Electric Company
Iowa Power and Light Company
Iowa Public Service Company
 Corn Belt Power Cooperative
Iowa Southern Utilities Company
Lake Superior District Power Company
Lincoln Electric System
Minnesota Power & Light Company
Minnkota Power Cooperative, Inc.
Missouri Basin Municipal Power Agency
Montana-Dakota Utilities Co
Muscatine Power and Water
Nebraska Public Power District
Northern States Power Company
Northwest Iowa Power Cooperative
Northwestern Public Service Company
Omaha Public Power District
Otter Tail Power Company
United Power Association
Western Area Power Administration - Billings Area

NORTHEAST POWER COORDINATING COUNCIL
(NPCC)

New England Power Pool (NEPOOL)

System Identification

- (1) Bangor Hydro Electric Company
- Boston Edison Company
- Braintree Electric Light Department
- Burlington Electric Department
- Cambridge Electric Light Company
- Canal Electric
- Central Maine Power Company
- Central Vermont Public Service Corporation
- (1) Chicopee Electric Light Department
- (1) Citizen's Utilities
- Connecticut Light & Power Company
- Connecticut Yankee Atomic Power Company
- Eastern Utilities Associates System
- (1) Fitchburg Gas & Electric Light Company
- Green Mountain Power
- Hartford Electric Light Company
- (1) Holyoke Gas & Electric Department
- Holyoke Water Power Company
- (1) Hudson Light & Power Department
- (1) Ipswich Municipal Light Department
- Maine Electric Power Company
- (1) Maine Public Service Company
- Maine Yankee Atomic Power Company
- Mass. Municipal Wholesale Electric Company
- (1) Marblehead Municipal Light Department
- Montaup Electric Company
- New Bedford Gas & Edison Light Company
- New England Electric System
- New England Gas & Electric Association
- (1) Newport Electric Corporation
- Northeast Utilities
- (1) Norwalk, Second Taxing District
- (1) Norwich, City of
- (1) Peabody Municipal Light Department
- Public Service Company of New Hampshire
- (1) Shrewsbury Electric Light Department
- (1) Taunton Municipal Light Department
- United Illuminating Company
- Vermont Group
- Vermont Yankee Nuclear Power Corporation
- (1) Wallingford Electric Department
- Western Massachusetts Electric Company
- Yankee Atomic Electric Company

- (1) Non-Member of NPCC

NPCC (Cont.)

New York Power Pool (NYPP)

System Identification

- (1) Central Hudson Gas & Electric Corporation
- (1) Consolidated Edison Company of New York, Inc.
- (1) Village of Freeport
- (1) Jamestown Municipal Electric System
- (1) Long Island Lighting Company
- (1) New York State Electric & Gas Corporation
- (1) Niagara Mohawk Power Corporation
- (1) Orange and Rockland Utilities, Inc.
- (1) City of Plattsburgh
- (1) Power Authority of the State of New York
- (1) Rochester Gas and Electric Corporation
- (1) Non-Member of NPCC

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
(SERC)

FLORIDA SUBREGION

Florida Power Corporation
Florida Power & Light Company
Fort Pierce Utilities Authority
City of Gainesville
City of Homestead
Jacksonville Electric Authority
Lake Worth Utilities Authority
City of Lakeland
New Smyrna Beach Utilities Commission
Orlando Utilities Commission
Sebring Utilities Commission
Seminole Electric Cooperative
Southeastern Power Administration
City of Tallahassee
Tampa Electric Company
City of Vero Beach

SOUTHERN COMPANIES SUBREGION

Alabama Electric Cooperative, Inc.
Alabama Power Company
Crisp County Power Commission
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Savannah Electric & Power Company
Southeastern Power Administration
South Mississippi Electric Power Assn.

TENNESSEE VALLEY SUBREGION

Nantahala Power & Light Company
Tapoco, Inc.
Tennessee Valley Authority

VIRGINIA - CAROLINAS SUBREGION

Carolina Power & Light Company
Duke Power Company
South Carolina Electric & Gas Company
South Carolina Public Service Authority
Southeastern Power Administration
Virginia Electric & Power Company
Yadkin, Inc.

SOUTHWEST POWER POOL
(SPP) or (SWPP)

SPP - GROUP A

Arkansas Electric Cooperative Corporation
Cajun Electric Power Cooperative, Inc.
Central Louisiana Electric Company, Inc.
Gulf States Utilities Company
Middle South Utilities, Inc.
 Arkansas Power & Light Company
 Arkansas-Missouri Power Company
 Louisiana Power & Light Company
 Mississippi Power & Light Company
 New Orleans Public Service Inc.
City of Ruston, Louisiana
Greenwood Utilities

SPP - GROUP B

Grand River Dam Authority
Oklahoma Gas and Electric Company
Public Service Company of Oklahoma
Southwestern Electric Power Company
Southwestern Power Administration
Southwestern Public Service Company
Western Farmers Electric Cooperative

SPP - GROUP C

Board of Public Utilities, Kansas City, KA
Central Kansas Power Company, Inc.
Chanute Municipal Utilities
Coffeyville Municipal Water & Light Department
City Power & Light, Independence, MO
The Empire District Electric Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
The Kansas Power & Light Company
Missouri Public Service Company
St. Joseph Light & Power Company
Sunflower Electric Cooperative
Winfield Municipal Light & Water
Western Power Division - Central Telephone & Utilities Corp.

SPP - GROUP D

City Utilities, Springfield, MO

SPP - GROUP E (Non-Members)

Ponca City (OK) Water & Light
Jonesboro (AR) City Water & Light

This report includes data from 33 of SPP's 41 member systems. By prior arrangement, the following members have submitted their data to the councils indicated:

Associated Electric Cooperative, Inc.	(MAIN) ^{1/}
Missouri Utilities Company	(MAIN)
Missouri Power & Light Company	(MAIN)
Missouri Edison Company	(MAIN)
West Texas Utilities Company	(ERCOT)

1/ Transferred to SPP as of June 1, 1980

WESTERN SYSTEMS COORDINATING COUNCIL
(WSCC)

MEMBER SYSTEMS (47)

Arizona Electric Power Cooperative, Inc.
Arizona Power Authority
Arizona Public Service Company
Black Hills Power & Light Company
Bonneville Power Administration
British Columbia Hydro & Power Authority (Canadian System)
Calgary Power Ltd. (Canadian System)
Colorado Springs, City of
Colorado-Ute Electric Association, Inc.
Corps of Engineers (North Pacific Division)
Department of Water Resources/California
El Paso Electric Company
Eugene Water & Electric Board (Oregon)
Glendale Public Service Department
Idaho Power Company
Los Angeles Department of Water and Power
Metropolitan Water District/Southern California
Montana Power Company, The
Nevada Power Company
Pacific Gas & Electric Company
Pacific Power & Light Company
Pasadena, City of
Plains Electric Generation and Transmission Cooperative, Inc.
Platte River Power Authority
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Mexico
PUD No. 1 of Chelan County
PUD No. 1 of Cowlitz County
PUD No. 1 of Douglas County
PUD of Grant County
Puget Sound Power & Light Company
Sacramento Municipal Utility District
Salt River Project
San Diego Gas & Electric Company
Seattle Department of Lighting (Seattle City Light)
Sierra Pacific Power Company
Southern California Edison Company
So. Colorado Power Division, Central Tele. & Util. Corp.
Tacoma Department of Public Utilities (Tacoma City Light)
Tri-State G & T Association, Inc.
Tucson Electric Power Company
Utah Power & Light Company
Washington Water Power Company, The
Water and Power Resources Service
 (Denver Federal Center) (Southwest)
 (Lower Colorado) (Upper Colorado)
 (Lower Missouri) (Upper Missouri)
 (Mid-Pacific) (Pacific Northwest)

West Kootenay Power & Light Company (Canadian System)
Western Area Power Administration

(Golden, Colorado)
(Boulder City, Nevada)
(Denver, Colorado)
(Sacramento, California)
(Salt Lake City, Utah)
(Billings, Montana)

AFFILIATE MEMBERS (14)

Anaheim, City of
Bountiful City Light and Power
Electrical District No. 2, Coolidge, Arizona
Garkane Power Association, Inc.
Lamar Utilities Board (City of Lamar)
Lodi, City of
Navajo Tribal Utility Authority
Northern California Power Agency
Palo Alto, City of
PUD of Clark County, Vancouver, Washington
Redding, City of
Riverside, City of
St. George, City of
Santa Clara, City of

PARTICIPANTS IN THIS REPORT

This report has been prepared by personnel of the Power Supply Planning Branch, Division of Power Supply and Reliability. All references to "Staff" mean the personnel of the Washington Office of the Branch. The Electric Region Analyses of Section XI were prepared by personnel of the Division's Field Offices and were reviewed by Washington Office Staff. Each Field Office was assigned a Reliability Council area and the Electric Regions within that Council, according to the following schedule:

Atlanta, Ga. (SERC)	William F. Scott Thomas R. Fitz, Jr.
Chicago, Ill. (ECAR, MAIN, MARCA)	Herbert R. Rinder Harold H. Krefft
Fort Worth, Tx. (ERCOT, SWPP)	Johnny Ray Johnson Raymond P. Mullikin
New York, N.Y. (ECAR, MAAC, NPCC)	Gilbert J. Cigal Vincent Hom Jonas Parish
San Francisco, Cal. (WSCC)	Robert Van Slambrook Melvin L. Cone Donald Rushton

Sections I through IX (except for Part 2 of Section VII) were prepared by Norton Savage with the assistance of John Emami and Samuel J. Ferraro, Jr. Section X is mainly the work of Samuel J. Ferraro, Jr. Part 2 of Section VII is the work of Anthony J. Como and Clark Spitler. Reviews of the Regional analyses prepared by the Field Offices were accomplished by Anthony J. Como, Clark Spitler and John Emami with assistance from Michael Sheehan. Anthony J. Como was responsible for liaison between the Field Offices and the Washington Office and for coordination of the regional analyses.

Direct responsibility for organization and completion of the report was given to William Graban, Chief of the Power Supply Planning Branch. Over-all review of the document on behalf of the Division Director was undertaken by Phillip Layfield, Assistant to the Division Director. General managerial responsibility for scope, focus, contents and work assignments was exercised by Richard F. Weiner, Director of the Division of Power Supply and Reliability.

Skilled assistance in the onerous task of typing and re-typing the text and the many tabular presentations was provided by the secretarial personnel of the Division: Theresa Piser, Elnora Douglas,

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Jerry L. Pfeffer
Assistant Administrator
Office of Utility Systems

XI.1.1

SECTION XI.1

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

(ECAR)

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

The East Central Area Reliability Coordination Agreement (ECAR) was consummated January 14, 1967. This agreement created an organization, the purpose of which is to augment reliability of bulk power supply through coordination of planning and operation of generation and transmission facilities in the East Central area. The ECAR area covers all or portions of nine states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The bulk power membership currently consists of 26 companies (19 systems); 25 are investor-owned and 1 is a cooperative. They are as follows:

- Appalachian Power Company (AEP)
- Cincinnati Gas & Electric Company
- Cleveland Electric Illuminating Company
- Columbus and Southern Ohio Electric Company
- Consumers Power Company
- Dayton Power and Light Company
- Detroit Edison Company
- Duquesne Light Company
- East Kentucky Power Cooperative
- Indiana & Michigan Electric Company (AEP)
- Indiana-Kentucky Electric Corporation
- Indianapolis Power & Light Company
- Kentucky Power Company (AEP)
- Kentucky Utilities Company
- Louisville Gas and Electric Company
- Monongahela Power Company (APS)
- Northern Indiana Public Service Company
- Ohio Edison Company
- Ohio Power Company (AEP)
- Ohio Valley Electric Corporation
- Pennsylvania Power Company
- Potomac Edison Company (APS)
- Public Service Company of Indiana
- Southern Indiana Gas and Electric Company
- Toledo Edison Company
- West Penn Power Company (APS)

XI.1.3

Seven power pooling groups are located within ECAR, and can be geographically grouped within the following Department of Energy/Economic Regulatory Administration Electric Region boundaries:

<u>Electric Region</u>	<u>Identification</u>
1	Allegheny Power System (APS)
2	American Electric Power System (AEP)
13	Central Area Power Coordination Group (CAPCO)
14	Cincinnati, Columbus, Dayton Group (CCD)
15	Kentucky Group
16	Indiana Group (includes all Indiana utilities except Indiana & Michigan Electric Co.)
18	Michigan Electric Coordinated Systems (MECS)

The data and information included in the following sections include not only those of the power pool members within the Electric Regions, but also those of other electric systems which are within the region and report data to ECAR.

The Ohio Valley Electric Corp. (OVEC) was originally formed by a consortium of ten electric companies in ECAR to provide electric power to the Department of Energy Uranium Enrichment Plant at Portsmouth, Ohio. OVEC and its subsidiary Indiana-Kentucky Electric Corp. have two coal-fired steam electric plants to supply the load. For the purposes of this report, the OVEC load and capacity are considered as separate entities, not assigned to an Electric Region but included in the total ECAR figures.

American Electric Power System (AEP)
ELECTRIC REGION 2

Historical Perspective

The American Electric Power System Region includes American Electric Power Company and Buckeye Power Inc. The American Electric Power Company is an electric utility holding company comprising seven wholly-owned subsidiary companies operating in parts of the seven states of Ohio, Indiana, Michigan, West Virginia, Virginia, Kentucky and Tennessee.

The principal operating companies comprising of AEP System are: Ohio Power Company, Indiana & Michigan Electric Company, Appalachian Power Company, Wheeling Electric Company, Kingsport Power Company, and Michigan Power Company. In addition, the American Electric Power Service Corporation has been established, as a subsidiary of the AEP Company, to furnish engineering and other specialized services to the operating companies.

The American Electric Power System, while comprising the seven principal operating companies, functions as a single, integrated power system. Buckeye Power Co. is included. This objective is accomplished administratively by the fact that the president of the parent company is also the president of each of the operating subsidiaries as well as of the AEP Service Corporation. In addition, the major Buckeye power plant output is dispatched by AEP. The centralized planning, engineering design, construction and operation of major generation and transmission facilities assures the most economic and reliable design and operation of the AEP region as an integrated unit. Furthermore, this arrangement permits coordination of load projections, planning for reserves, system stability studies, joint or staggered participation in facilities development, exchanges of capacity and energy, maintenance, and economic dispatch.

Operations of the integrated system are coordinated from a single dispatch center located in Canton, Ohio.

The seven AEP operating companies in 1978 served almost 2 million customers, of which 1,750,000 were residential 204,000 commercial, 13,000 were industrial, and 9,000 others. Buckeye does not serve individual consumers directly.

XI.1.5

The AEP System though geographically spread out among seven states and seven companies, still is a highly integrated system with major transmission ties of 765 KV, 500 KV, 345 KV and 138 KV. Many inter-connections exist with ECAR systems and with the neighboring power pools of SERC, MAAC, and MAIN.

Buckeye Power Inc. is essentially an association of all of the electric cooperatives in the state of Ohio. Its mission is to generate electric power for the State's Co-op customers. As such, Buckeye has generating facilities consisting of 2 units, a 630 MW and a 600 MW at the Cardinal electric generating plant. Also located at this plant is a third unit owned by Ohio Power Company, a subsidiary of American Electric Power Company. The station is managed and operated by Cardinal Operating Company for the individual owners. Through an agreement between Buckeye and AEP, Buckeye is allowed to purchase power from Ohio Power Company in the event that Buckeye's units are unable to satisfy the company's requirements. The agreement also provides for Ohio Power to use excess generating capacity from Buckeye's Cardinal Plant units until the Buckeye load requirements grow to meet the plant capability.

The AEP region has historically been a winter peaking region. Shown below are the region's summer and winter peaks for the period 1977-1979.

TALBE 1B.1 HISTORICAL PEAK DEMAND - MW AEP REGION

	<u>Summer</u>				<u>Winter</u>		
	June	July	Aug	Sep	Dec	Jan	Feb
1978	<u>10595</u>	<u>11735</u>	11025	11129	12457	<u>13192</u>	<u>12913</u>
1979	11161	<u>11494</u>	11421	<u>11685</u>	12486	<u>13824</u>	13773
1979	10813	11568	<u>11981</u>	<u>11236</u>	13035	<u>13129</u>	13571

Underline indicates seasonal peak

XI.1.6

The summer peak demands are highly dependent on climate conditions and are temperature/humidity sensitive. In the three reported years the peak has occurred in three different months.

The winter peak usually occurs in January or February. A shift in the winter peak from these months is generally the result of a weather bias. There is occasionally some sensitivity to unusual economic conditions in the region as well.

The following table shows generating capacity down for schedule maintenance performed each period and also the capability unavailable because of forced unit and partial unit outages.

TABLE 1P.2
SCHEDULED MAINTENANCE AND UNAVAILABLE CAPABILITIES
AEP REGION

	<u>Scheduled</u> <u>Maintenance</u> <u>(MW)</u>	<u>Other</u> <u>Unavailable</u> <u>(MW)</u>	<u>Total</u> <u>Unavailable</u> <u>(MW)</u>	<u>Scheduled</u> <u>Maintenance</u> <u>(MW)</u>	<u>Other</u> <u>Unavailable</u> <u>(MW)</u>	<u>Total</u> <u>Unavailable</u> <u>(MW)</u>
1977	350	1936	2286	295	4418	4713
1978	1030	2390	3420	189	2508	2697
1979	1898	1770	3668	1190	2773	3963

The percentage of installed capability that was unavailable for reasons other than scheduled maintenance varied from 9-12% during 1977-1979 in the summer and from 13-24% in the winter. For the 1st quarter of 1980 daily forced rates averaged about 13%.

The reserve margins for the 1977-1979 period are shown below. The table indicates the effects of scheduled maintenance and other outages.

TABLE 1B.3
HISTORICAL SEASONAL RESERVES
AEP REGION

Summer

	<u>Peak</u> <u>Demand</u> <u>MW</u>	<u>Total</u> <u>Capability</u> <u>(MW)</u>	<u>Total</u> <u>Reserves</u> <u>(%)</u>	<u>Capability</u> <u>After</u> <u>Maintenance</u> <u>(MW)</u>	<u>Available</u> <u>Reserves</u> <u>(%)</u>	<u>Actual</u> <u>Capability</u> <u>(MW)</u>	<u>Actual</u> <u>Reserves</u> <u>(%)</u>
1977	11735	15604	33.0	15254	30.0	13318	13.5
1978	11685	18131	55.5	17101	46.7	14711	26.2
1979	11981	18312	52.8	16414	37.0	14644	22.2

Winter

1977	13192	18724	41.9	18429	39.7	14011	6.2
1978	13824	18738	35.5	18549	34.2	16041	16.0
1979	13603	18170	33.6	16980	24.8	14207	4.4

Winter actual reserves were adequate even considering the effects of scheduled and forced outages. Summer operating reserves were high but not excessive.

AEP's policy of large installed reserves of coal-fired generation is used to advantage by selling capacity to other utilities in the region.

Shown below are the energy requirements, summer and winter demands and annual load factors for the 1977-1979 period.

TABLE 1B.4
HISTORICAL ENERGY, PEAKS AND LOAD FACTORS
AEP REGION

	<u>Energy Requirements</u>		<u>Sumer</u> <u>Peak Demand</u>		<u>Winter</u> <u>Peak Demand</u>		<u>Annual</u> <u>Load</u> <u>Factor</u>
	<u>(Gwh)</u>	<u>(Growth-%)</u>	<u>(MW)</u>	<u>(Growth-%)</u>	<u>(MW)</u>	<u>(Growth-%)</u>	<u>(%)</u>
1977	74203	2.6	11735	-	13192	-	64.2
1978	76143	4.3	11658	(0.7)	13824	4.8	62.9
1979	79420	3.5	11981	2.8	13603	(1.6)	66.6
% Growth 1977-79	3.5			1.0		1.5	

Energy requirements over the period 1977-1979 have grown at a compound rate of 3.5%. This is higher than most other regions in ECAR and reflects AEP's geographical dispersal and diversity in sales, including sales to other utilities. It also is indicative of the economic stability in the service area.

Summer peak demand growth rates for 1977-1979 are considerably less than their tradition patterns. This is due in part to cool summers but mainly to conservation techniques and the increased cost of energy. Load factors were high, because of AEP's large round the clock industrial load segment, and because of the greater growth of energy requirements in relation to demands.

Current Perspective

The projected 1980 summer and winter non-coincident peak demand requirements are shown below.

TABLE 1B.5
PROJECTED 1980 SEASONAL PEAK DEMAND - MW
AEP REGION

<u>Summer</u>			<u>Winter</u>		
June	July	August	December	January	February
11387	11564	<u>11974</u>	13713	<u>14322</u>	14233

The summer demand is projected to be 16% less than the winter demand, which affords the opportunity for the performance of scheduled maintenance.

The 1980 winter installed capability of the AEP region is estimated to be 20031 MW and the winter non-coincident AEP/Buckeye peak demand requirements are projected to be 14322 MW excluding 315 MW of AEP interruptible demand. After adjustments for scheduled receipts and deliveries, net reserves are 5566 or 33.8%.

In the ECAR ERA-411 report for the future (1980-1989) AEP does not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an indication of scheduled maintenance for the entire region.

The estimate prepared for the 411 report, is based on the level of planned maintenance that is currently projected for the periods of heaviest load demand during the upcoming summer and winter seasons, i.e., five percent of total installed capability during the summer of 1980 and five percent of total installed capability during the winter of 1980-1981.

The summer and winter 1980 reserve margins for the AEP electric region are shown below.

TABLE 1P.6
1980 RESERVES MARGINS*
AEP REGION

<u>SUMMER</u>						<u>WINTER</u>					
<u>Planned Reserves</u>		<u>Total Reserves</u>		<u>Available Reserves**</u>		<u>Planned Reserves</u>		<u>Total Reserves</u>		<u>Planned Reserves**</u>	
<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>
6484	54.1	6590	55.0	5666	47.3	5709	39.8	5566	38.8	4564	31.9

* Based on ERA Form 411

** 5% of total installed capability assumed - from ECAR ERA-411 Report of Scheduled Outages

The margins shown above have not been adjusted for unscheduled outages of generating equipment since the amount of these outages are generally unknown ahead of time, but have run as high as 24% in 1977. As previously indicated the recent experienced forced outage rate is about 13%. If these outages for 1980 do not exceed the maximum outages of the 1977-79 period, 12% of installed capacity during the summer period and 23% during the winter, the resultant available reserves would be 3450 or 28.8% for the summer, and (43) MW or (-0.3)% for the winter.

The winter 1980/81 capability of the generating facilities installed in the AEP region will be 20031 MW. The capability breakdown by fuel types is shown below.

TABLE 1P.7
1980/81 WINTER INSTALLED CAPABILITY IN MW
AEP REGION

	<u>Nuclear Steam</u>	<u>Coal Steam</u>	<u>Combustion Turbine-Oil</u>	<u>Hydro Convent</u>	<u>Pumped Storage</u>	<u>Total Capability</u>
	2105	17080	18	223	560	20031
% of Total	10.7	85.3	0.1	1.1	2.8	100.0

Of the current capability, 85% is coal-fired-steam capability, 11% nuclear-steam, 3.0% pumped storage, 1% conventional hydro-electric and less than 0.1% is oil-fired combustion turbine. Included in the 1980/81 capability are two units; Mountainer #1 a coal-fired unit 1300 MW capability to be installed in December 1980 and Smith Mountain #3 a pumped storage unit-100 MW capability to be installed in February 1980 but now delayed until 1981.

The projected 1980 energy requirements, summer and winter demand requirements and annual load factor for the region are shown below:

TABLE 1B-8
1980 REQUIREMENTS
AEP REGION

	<u>Energy Requirements</u> (Gwh)	<u>Summer Peak Demand</u> (MW)	<u>Winter Peak Demand</u> (MW)	<u>Annual L.F.</u> (%)
	82170	11987	14322	65.3
% Growth 1980/1979	3.5	(0.5)	5.3	

The anticipated 1980 projected energy requirements indicate a projected growth rate of 3.5% the same rate as the 1977-1979 period. The summer peak is expected to decline slightly and the winter peak is expected to grow 5.3%. The winter peak's growth has been erratic, at 4.8% from 1977-1978 and a decline of 1.6% from 1978-1979.

Delays of future critical bulk power transmission facilities that will not be in service when needed are reported under Item 5-C of the ERA-411 report. Two such lines, that impact adversely the system were originally scheduled for 1980 installation but have been delayed. These are discussed below.

Culloden-Wyoming 765 kV Line

The completion of the 57 mile long Culloden-Wyoming 765 kV line of the Appalachian Power Company -- extending from a new switching station to be located near the existing Amos-Baker 765 kV circuit in the vicinity of Culloden, West Virginia, to a new 765/138 kV station to be located near Oceana, in Wyoming County, West Virginia -- is presently scheduled for November 1981. The most recent delay of this line from November 1980 to November 1981 was necessitated by the Company's inability to raise funds through the sale of senior securities. This line is intended to establish a third EHV channel into the central portion of the Appalachian Power Co. (APCo) network, thereby maintaining an adequate level of reliability of bulk power supply to the APCo load south of Charleston, West Virginia. In addition, it will enhance the reliability of power plant outlets from the Amos-Gavin-Mountaineer generating complex.

In the absence of this line for the winter 1980/81 peak loads, it is anticipated that -- during certain transmission outages involving the existing facilities supplying APCo's load areas south of Charleston, WV. -- serious overloads may occur on some of the remaining transmission facilities. Should any of the overloaded facilities fail, or be taken out of service by their protective equipment, other facilities may become overloaded and, in turn, may become subject to failure or disconnection. As a result, a cascading interruption in electric service to portions of Appalachian Power Co., Kingsport Power Co., and Kentucky Power Co., is becoming a real possibility. Furthermore, the flexibility of dispatching on an economic basis, some 6,800 MW of generating capacity in the Amos-Gavin-Mountaineer area could be severely hampered with potential forced curtailments necessary under certain contingency conditions.

While minor upgrading of transmission facilities during the 1980 to 1982 period is being initiated in order to minimize the risk of a cascading disturbance, any further delay of the Culloden-Wyoming 765 kV line beyond November 1981 as a result of continuing financial restrictions will increase the possibility of a major areas wide interruption of electric power supply.

Gavin-Culloden 765 kV Line

The 33 mile Gavin-Culloden 765 kV line of the Appalachian Power Company (APCo), associated with the Mountaineer #1 1,300 MW generating unit, was scheduled for service in May 1980. This line is required to provide the needed transmission capacity for carrying the electric power generated at the Gavin-Mountaineer complex (3,900 MW) -- located on the Ohio River in the vicinity of Cheshire, Ohio, and New Haven, West Virginia -- to various load centers on the system. In the absence of this line, generating capacity curtailments will be necessary -- following the permanent outage of one of the existing 765 kV transmission outlets from this generating complex -- so as to avoid the total loss of 3,900 MW of capacity due to instability, should a subsequent fault occur on one of the remaining 765 kV lines.

In 1977, Appalachian Power Co. (APCo) filed with the West Virginia Public Service Commission a petition for a Certification of Convenience and Necessity for the subject line. Following extensive hearings, the record was closed in June 1978 and a certificate was granted by the Public Service Commission in May 1979. This decision was appealed to the West Virginia Supreme Court which upheld the Public Service Commission in a December 1979 order. As a result of the delay in receiving the final decision, the in-service date for this line has been rescheduled to December 1982 -- more than two years after the start-up of the Mountaineer 1,300 MW generating unit.

Future Perspective

The range of total reserves for the AEP region for the period 1981-1985 and 1986-1989 are tabulated below:

TABLE 1B.9
RANGE OF AEP TOTAL RESERVES - %
AEP REGION

<u>1981 - 1985</u>		<u>1986 - 1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
48.0-58.0	25.5-31.7	42.1-47.9	21.9-27.7

As seen above, the net reserves spans a large range from 21.9% in the winter 1989/90 to 58.0% in the summer of 1981. Indications are there will be no difficulty in meeting obligations, if there are no unusual delays in completing scheduled capacity additions. However, new in-service dates for four 1300 MW coal-fired units furnished after the ERA 411 report was finalized may have altered the conclusions derived from the ERA 411 report. Total unavailable capacity including scheduled maintenance in the 1977-1979 period ranged from 14-25% of installed capability for the winter peak season. If an average outage rate of 20% is assumed for the 1981-89 period only in the winter of 1989/90 would available reserves be deficient, using the ERA 411 in-service dates. Using the new in-service dates provided by AEP, deficits would occur in all the winter seasons starting in 1983. These would range from 536 MW to 1542 MW in 1989. All summer actual reserves throughout the study period would be adequate.

Shown below are the projected growth rates of demand and capability for each period and the overall rates for 1981-1989.

TABLE 1B.10
PROJECTED ENERGY AND DEMAND GROWTH RATES
AEP REGION

	Energy Requirements GWH)	%	Summer Peak Demand (MW)	%	Winter Peak Demand (MW)	%	Annual Load Factor %
1981	85,760		12,414		15,067		65.0
1982	89,360		12,995		15,710		64.5
1983	93,190		13,497		16,330		65.1
1984	97,130		13,992		16,961		65.4
1985	101,280		14,950		17,781		64.8
Growth 81-85		4.2		4.7		4.2	
1986	105,720		15,515		18,437		65.5
1987	108,350		16,075		19,114		64.7
1988	111,980		16,657		19,808		64.5
1989	115,620		17,261		20,527		64.3
Growth 86-89		3.1		3.6		3.7	
Growth 81-89		3.7		4.3		3.9	

The 1981-1985 summer demands are projected to grow at a compound rate of growth of 4.7%, 1986-1989 3.6%; and overall 1981-89, at 4.3%. These rates are considerable higher than the summer 1977-1979 growth of 1%.

The winter demand growth rates are projected to grow at a compound rate of 4.2 for the 1981-1985 period, 3.7% for the 1986-1989 period, with an average overall 1981-89 rate of 3.9% as compared to the 1977-79 rate of 1.5%.

Energy requirements are projected to grow 4.2% from 1981-1985, 3.1% from 1986-1989 and 3.7% for the overall period from 1981-1989. Historically 1977-1979, the energy growth was at 3.5%. This would indicate continued optimistic economic activity in the region.

During the 1981-1985 period four generating units are expected to be placed in service. Two of these units will be conventional hydro, and two are coal-fired steam. The conventional hydro units are at Racine and Gallipolis, rated at 40 MW each with an in-service dates of December 1981 and July 1985 respectively. The two steam electric units are at Rockport, and each is rated at 1300 MW, with in-service dates of June 1983_{1/} and December 1984._{1/}

In the 1986-1989 period, two 1300 MW coal-fired steam-electric units, located in Lewis County, are scheduled for installation during July 1986_{1/} and December 1988._{1/}

The winter capability of units installed in the region for the period 1980-1989 is shown by fuel type in Table 1B.18. Major generating unit additions during the period are given in Table 1B.19. The percentages of each type of capability for the target years 1980, 1984 and 1989 are given below.

TABLE 1B.11
PLANNED GENERATING CAPABILITY BY TYPE OF FUEL - % _{2/}
AEP REGION

	<u>Nuclear Steam</u>	<u>Coal Steam</u>	<u>Combustion Turbine-Oil</u>	<u>Hydro Conv.</u>	<u>Pumped Storage</u>	<u>Total Capability</u>
1980	10.7	85.3	0.1	1.1	2.8	100.0
1984	9.4	86.9	0.1	1.2	2.4	100.0
1989	8.4	88.1	0.1	1.2	2.2	100.0

1/ See Table 1B.19 for new in-service dates.

2/ Uses 411 in-service dates.

Coal presently is the primary fuel for about 85% of the installed capacity of the region. Only a slight change to about 88% is forecasted for the future, due to the addition of 5200 MW of coal-fired capacity after 1980. Nuclear-steam capacity will decline from 11% to 8% since no new nuclear capacity is scheduled. The remaining 4% of capacity in 1989 will be provided by pumped storage, conventional hydroelectric and one small oil-fired combustion turbine.

There is one critical bulk power transmission facility that will not be in service when desired during the period 1981-1989, the Appalachian Power Company's (APCo) 72 mile Jackson's Ferry-Axton 765 kV line. This is intended to extend EHV supply eastward from the existing Jackson's Ferry Station located near Axon, Virginia to the new Axton 765 kV Station, located near Axon, Virginia. The line and the associated 138 kV facilities -- planned for service by November 1982 just prior to the most recent delay -- will provide the necessary transmission reinforcement to APCo's eastern area so as to maintain an adequate level of reliability for the bulk power supply system serving that region. In addition, these facilities will provide local support to the Martinsville and Danville, Virginia, load centers located in the vicinity of the new Axton Station. In the absence of the Jackson's Ferry-Axton 765 kV line, local and area-wide electric service interruptions are becoming a very real possibility.

APCO applied in early 1974 to the Virginia State Corporation Commission (SCC) for a Certificate of Public Convenience and Necessity to construct the Jackson's Ferry-Axton 765 kV line. On July 5, 1974, the SCC found that the line was needed and in October 1979, following extensive hearings, approved a line route. However, before APCo can begin right-of-way acquisition and construction, a permit to cross the Blue Ridge Parkway must be granted by the National Park Service of the United States Department of the Interior. The National Park Service is now in the process of carrying out investigations regarding the crossing of the Blue Ridge Parkway.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure and the material which appears in the

final ECAR report is normally limited to those items which are of particular significance to the overall region. The appraisal is based on a careful analysis of various studies carried out by the ECAR Transmission System Performance Working Group under the direction of the Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions was considered during the course of the various studies referred to above and the following operating procedures were developed (only AEP described below).

AEP--Central Appalachian Area

Heavy facility loadings may be experienced in AEP's Central Appalachian area during projected winter 1979-80 peak load conditions, and may limit the transfer of power to the south (TVA) and southeast (Duke Power Co., Carolina Power and Light, and Virginia Electric and Power Co.) during certain transmission outage conditions. Since the Central Appalachian load area is winter peaking, this local problem is not anticipated during summer peak load conditions.

The performance of the Central Appalachian area is under continuing study by AEP, and detailed information has been developed for system operators so that all adverse system conditions can be fully assessed, and appropriate remedial action can be taken. EHV reinforcement to the area is presently planned for the fall of 1981.

AEP--Ridgeway Series Reactor

Transfers of power into ECAR from the southeast may be limited by loadings on the Dan River Ridgeway (Duke-AEP) 138 kV interconnection following an outage of the Jackson's Ferry-McGuire 500 kV circuit. Power flows on the 138 kV tie can be reduced, however, by insertion of series reactors located at AEP's Ridge-way Station. These reactors are inserted by remote control whenever the tie line loadings approach the circuit capability.

The most recent ECAR appraisal studies were for Summer 1979 and Winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

TABLE 1P.12

EMERGENCY TRANSFER CAPABILITY - MW
AEP REGION

<u>Transfer</u>	<u>Summer 1979</u> <u>Capability</u>	<u>Winter 1979-80</u> <u>Capability</u>
ECAR to MAAC	3300+	3300+
ECAR to NPCC (NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC (VACAR)	1250	1900*
ECAR from MAAC	2450	3300
ECAR from NPCC (NYPP)	3300+	2900
ECAR from MAIN	4000+	3800
ECAR from SERC (TVA)	2000	2100
ECAR from SERC (VACAR)	2700	2950

* ETC Values determined with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No. 1. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No.1 without suffering area-wide break-up and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to provide the facilities shown. Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed as a result of excessive lag in the certification process or as a result of difficulties in financing these projects due to inadequate rate relief, then appropriate short term operating procedures will need to be developed in order to maintain, to the greatest extent possible, the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, are as follows:

TABLE 1E.13
SUMMER 1984 EMERGENCY TRANSFER CAPABILITY - MW
AEP REGION

<u>Transfer</u>	<u>ETC</u> <u>MW</u>	<u>Transfer</u>	<u>ETC</u> <u>MW</u>
ECAR to MACC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC	2000
ECAR to MAIN	2900	ECAR from MAIN	4000+
ECAR to SERC (TVA)	2500	ECAR from SERV (TVA)	3200
ECAR to SERC (VACAR)	2250	ECAR from SERC (VACAR)	5500

The following table is a list of proposed bulk power lines to be constructed by AEP. It includes interconnections with other utilities and areas as well as internal transmission, many of these lines may become critical to AEP and its sales to other utilities in the region, thus impacting the reliability of neighboring systems.

TABLE 1B.14.1
LIST OF PROPOSED BULK POWER LINES
AEP REGION

Line Ownership List 01	Terminals 02	Line Length		Planned Service Date 05	Nominal Voltage in KV		Remarks 08
		KM 03	MI 04		OPER 06	DSGN 07	
American Electric Power System							
AEP	Lewis Co. / Hanging Rock-Jefferson	0.0	0.0	Mar 86	765	765	Provide Power Plant Outlet Loop into Lewis Co. Provide Power Plant Outlet
AEP	W. Bucyrus / Fostoria-Gallon	0.0	0.0	Jun 86	345	345	Loop into W. Bucyrus Provide support to the Bucyrus-Howard Area
AEP	Ohio Central / Kammer-Marysville	0.0	0.0	Jun 86	765	765	Loop into Ohio Central Reinforce Muskingum R.-Fostoria 345KV Loop
AEP	Lurich / Amos-Matt Funk	0.0	0.0	Oct 86	345	345	Date Change Loop into Lurich Provide support to Glen Lyn Area
AEP	Garden Creek Area / Stanley Valley	81.0	50.0	Nov 86	765	765	Date Change and Name Change Provide support to Kingsport Area Improve Interconnection Capability
AEP	Garden Creek Area / Baker-Broadford	0.0	0.0	Nov 86	765	765	Date Change Loop into Garden Creek
AEP	Marysville / West Bucyrus	72.0	45.0	Jun 87	345	345	1st Ckt-D/C Towers Reinforce Northern Ohio Power Co. 345KV System
AEP	Kanawha R. / Amos-Funk	0.0	0.0	Oct 87	345	345	Loop into Kanawha R. Provide support to Cabin Ck. - Beckley Area
AEP	Amos / Lurich	187.0	116.0	Nov 87	765	765	Date Change Provide support to Central and Eastern Apco Area

XI.1.19

TABLE 1B.14.2
LIST OF PROPOSED BULK POWER LINES
AEP REGION

Line Ownership List 01	Terminals 02	Line Length		Planned Service Date 05	Nominal Voltage in KV		Remarks 08
		KM 03	MI 04		OPER 06	DSGN 07	
American Electric Power System							
AEP	Kammer / South Canton	129.0	80.0	Jun 81	765	765	Provide support to Canton Area
AEP	Culloden / Amos-Baker	5.0	3.0	Nov 81	765	765	Date Change Loop into Culloden
AEP	Culloden / Wyoming	92.0	57.0	Nov 81	765	765	Provide support to Central Apoo Area
AEP	Allen / Sorenson-Robinson Park	0.0	0.0	Dec 81	345	345	Date Change Loop into Allen Improve Ft. Wayne Area Reliability
AEP	Rockport / Jefferson	179.0	112.0	Sep 82	765	765	Line Length Change Provide Power Plant Outlet
AEP	Mountainer / Culloden	67.0	42.0	Dec 82	765	765	Date Change Line Length Change Use with Gavin-Amos to form Mountain -EER-Amos & Culloden-Gavin Circuits Provide Power Plant Outlet
AEP	Hanging Rock / Jefferson	259.0	161.0	Jun 83	765	765	Provide Power Plant Outlets Provide East-West Transmission Cap. Provide Future Power Plant Outlets
AEP	Jackson's Ferry / Artor	116.0	72.0	Nov 83	765	765	Date Change Provide support to the Martinsville- Danville Area
AEP	Baker / Pigeon Roost	109.0	68.0	Nov 83	345	345	Date, Name, & Line Length Change Double Circuit Initial Operation at 138 KV Provide support to Sprigg-Logan Area
AEP	Rockport / Sullivan	155.0	97.0	Jun 84	765	765	Line Length Change

XL1.1.20

TABLE 1B.14.3
LIST OF PROPOSED BULK POWER LINES
AEP REGION

Line Ownership List 01	Terminals 02	Line Length		Planned Service Date 05	Nominal Voltage in KV		Remarks 08
		KM 03	MI 04		OPER 06	DSGN 07	
American Electric Power System							
AEP	Thomson Road / Cook-Twin Branch	0.0	0.0	Dec 87	345	345	Date Change Loop into Thomson Rd. Improve Benton Harbor Area Reliability
AEP	Axton / Joshua Falls	121.0	75.0	Nov 88	765	765	Date Change Provide support for Lynchburg Area and Martinsville-Danville Area
AEP	W. Millersport / Newark	29.0	18.0	Jun 89	345	345	1st Ckt-D/C Towers Provide support to Newark Area
AEP	Ohio Ctl. / Newark	35.0	22.0	Jun 89	345	345	1st Ckt-D/C Towers Provide support to Newark Area
AEP	Matt Funk / Jackson's Ferry-Cloverdale	0.0	0.0	Nov 89	765	765	Date Change Loop into Matt Funk
AEP	Lurich / Funk	48.0	30.0	Nov 89	765	765	Date Change Provide support to Eastern Apco Area

IX.1.1

TABLE 1B.14.4
LIST OF PROPOSED BULK POWER LINES
AEP REGION

Line Ownership List	Terminals	Line Length		Planned Service Date	Nominal Voltage in KV	
		KM	MI		OPER	DSGN
		03	04		05	06
Interconnections						
AEP TVA	Stanley Valley / Phipps Bend-Sullivan Name Change Loop into Stanley Valley Station Improve Area Reliability Increase Interchange Capability	0.0	0.0	Jun 83	500	500
AEP PSI	Jefferson / Marble Hill Deliver Generator Output	24.1	15.0	Jan 84	765	765
PSI AEP	Gwynneville / Jefferson-Greentown Loop into Gwynneville Deliver Generator Output	0.0	0.0	Jan 84	765	765
AEP TVA	Rockport / TVA (Total Line) Date Change Provide Power Plant Outlet	161.0	100.0	89	765	765

Table 1 B.15
HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
AEP REGION

	<u>1977</u>		<u>1978</u>		<u>1979</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	17566	18466	19315	19561	18754	19029
2. Peak Demand	11735	13192	11658	13824	11981	13603
3. Planned Reserves (1-2)	5831	5274	7657	5737	6773	5426
4. Planned Reserves (%) $(3\frac{1}{2}) \times 100\%$	49.7	40.0	65.7	41.5	56.5	39.9
5. Net Transactions (Imports-Exports)	-1962	258	-1184	-823	-442	-859
6. Total Capability (1+5)	15604	18724	18131	18738	18312	18170
7. Total Reserves (6-2)	3869	5532	6473	4914	6331	4567
8. Total Reserves (%) $(7\frac{1}{2}) \times 100\%$	33.0	41.9	55.5	35.5	52.8	33.6
9. Scheduled Maintenance	350	295	1030	189	1898	1190
10. Capability After Maintenance (6-9)	15254	18429	17101	18549	16414	16980
11. Reserves After Maintenance (10-2)	3519	5237	5443	4725	4433	3377
12. Reserves After Maintenance (%) $(11\frac{1}{2}) \times 100\%$	30.0	39.7	46.7	34.2	37.0	24.8
13. Inoperable Capability *	0	0	0	0	0	0
14. Available Capability (10-13)	15254	18429	17101	18549	16414	16980
15. Available Reserves (14-2)	3519	5237	5443	4725	4433	3377
16. Available Reserves (%) $(15\frac{1}{2}) \times 100\%$	30.0	39.7	46.7	34.2	37.0	24.8
17. Forced Outages	1936	4418	2390	2508	1770	2773
18. Actual Capability After Forced Outages (14-17)	13318	14011	14711	16041	14644	14207
19. Actual Reserves (18-2)	1583	819	3053	2217	2263	604
20. Actual Reserves (%) $(19\frac{1}{2}) \times 100\%$	13.5	6.2	26.2	16.0	22.2	4.4

* Included in item 17.

Table 1B.16
CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
AEP REGION

	1980	
	Summer	Winter
1. Planned Capability	18471	20031
2. Peak Demand	11987	14322
3. Planned Reserve (1-2)	6484	5709
4. Planned Reserve (%) $(3 \div 2) \times 100\%$	54.1	39.9
5. Net Transactions (Imports-Exports)	106	-145
6. Total Capability (1-5)	18577	19888
7. Total Reserves (6-2)	6590	5566
8. Total Reserves (%) $(7 \div 2) \times 100\%$	55.0	38.9
9. Scheduled Maintenance 1/	924	1002
10. Capability After Maintenance (6-9)	17653	18886
11. Reserves After Maintenance (10-2)	5666	4564
12. Reserves After Maintenance (%) $(11 \div 2) \times 100\%$	47.3	31.9
13. Inoperable Capability *	0	0
14. Available Capability (10-13)	17653	18886
15. Available Reserves (14-2)	5666	4564
16. Available Reserves (%) $(15 \div 2) \times 100\%$	47.3	31.9
17. Forced Outages *	0	0
18. Actual Capability After Forced Outages (14-17)	17653	18886
19. Actual Reserves (18-2)	5666	4564
20. Actual Reserves (%) $(19 \div 2) \times 100\%$	47.3	31.9

1/ Five percent of total planned capability assumed by ERA from ECAR-ERA 411 report

* No information supplied.

Table 1 B.17
FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
AEP REGION

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	19771	20211	19951	20211	21251	21511	21251	22811	22591	22851
2. Peak Demand	12412	15067	12995	15710	13497	16330	13992	16961	14950	17781
3. Planned Reserves (1-2)	7357	5144	6956	4501	7754	5181	7259	5850	7641	5070
4. Planned Reserves (%) (3÷2)×100%	59.3	34.1	53.5	28.7	57.4	31.7	51.9	34.5	51.1	28.5
5. Net Transactions (Imports-Exports)	-154	-457	-457	-457	-457	-457	-457	-465	-465	-542
6. Total Capability (1+5)	19617	19754	19494	19754	20794	21054	20794	22346	22126	22309
7. Total Reserves (6-2)	7203	4687	6499	4044	7297	4724	6802	5385	7176	4528
8. Total Reserves (%) (7÷2)×100%	58.0	31.1	50.0	25.7	54.1	28.9	48.6	31.7	48.0	25.5
9. Scheduled Maintenance *	0	0	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	19617	19754	19494	19754	20794	21054	20794	22346	22126	22309
11. Reserves After Maintenance (10-2)	7203	4687	6499	4044	7297	4724	6802	5385	7176	4528
12. Reserves After Maint- enance (%) (11÷2)×100%	58.0	31.1	50.0	25.7	54.1	28.9	48.6	31.7	48.0	25.5
13. Inoperable Capability *	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	19617	19754	19494	19754	20794	21054	20794	22346	22126	22309
15. Available Reserves (14-2)	7203	4687	6499	4044	7297	4724	6802	5385	7176	4528
16. Available Reserves (%) (15÷2)×100%	58.0	31.1	50.0	25.7	54.1	28.9	48.6	31.7	48.0	25.5
17. Forced Outages *	0	0	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	19617	19754	19494	19754	20794	21054	20794	22346	22126	22309
19. Actual Reserves (18-2)	7203	4687	6499	4044	7297	4724	6802	5385	7176	4528
20. Actual Reserves (%) (19÷2)×100%	58.0	31.1	50.0	25.7	54.1	28.9	48.6	31.7	48.0	25.5
COAL UNIT DELAYS PROJECTED BY ERA										
21. Possible Coal Delays	0	0	0	0	1300.0	1300.0	1300.0	1300.0	1300.0	1300.0
22. Actual Capability with Coal Delays (18-21)	19617	19754	19494	19754	19494	19754	19494	21046	20826	21009
23. Actual Reserves with Coal Delays (22-2)	7203	4687	6499	4044	5997	3424	5505	4085	5876	3228
24. Actual Reserves with Coal Delays (23÷2)×100%	58.0	31.1	50.0	25.7	44.4	21.0	39.3	24.1	39.3	18.2

* No information supplied.

Table 1 B.17.1
FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
AEP REGION

	1936		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22591	24151	23891	24151	25191	25451	25191	25451
2. Peak Demand	15515	18437	16075	19114	16657	19808	17281	20527
3. Planned Reserves (1-2)	7076	5714	7816	5037	8534	5643	7930	4924
4. Planned Reserves (%) (3÷2)x100%	45.6	31.0	48.6	26.4	51.2	28.5	45.9	24.0
5. Net Transactions (Imports-Exports)	-542	-606	-606	-274	-274	-344	-344	-420
6. Total Capability (1+5)	22049	23545	23285	23877	24917	25107	24847	25031
7. Total Reserves (6-2)	6534	5108	7210	4763	8260	5299	7586	4504
8. Total Reserves (%) (7÷2)x100%	42.1	27.7	44.9	24.9	49.6	26.8	43.9	21.9
9. Scheduled Maintenance *	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	22049	23545	23285	23877	24917	25107	24847	25031
11. Reserves After Maintenance (10-2)	6534	5108	7210	4763	8260	5299	7586	4504
12. Reserves After Maintenance (%) (11÷2)x100%	42.1	27.7	44.9	24.9	49.6	26.8	43.9	21.9
13. Inoperable Capability *	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	22049	23545	23285	23877	24917	25107	24847	25031
15. Available Reserves (14-2)	6534	5108	7210	4763	8260	5299	7586	4504
16. Available Reserves (%) (15÷2)x100%	42.1	27.7	44.9	24.9	49.6	26.8	43.9	21.9
17. Forced Outages *	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	22049	23545	23285	23877	24917	25107	24847	25031
19. Actual Reserves (18-2)	6534	5108	7210	4783	8260	5299	7586	4504
20. Actual Reserves (%) (19÷2)x100%	42.1	27.7	44.9	24.9	49.6	26.8	43.9	21.9
COAL UNIT DELAYS PROJECTED BY ERA								
21. Possible Coal Delays	0	1300	1300	1300	2600	1300	1300	1300
22. Actual Capability with Coal Delays (18-21)	22049	22245	21985	22577	22317	23807	23547	23731
23. Actual Reserves with Coal Delays (22-2)	6534	3808	5910	3463	5660	3999	6286	3204
24. Actual Reserves with Coal Delays (23÷2)x100%	42.1	20.7	36.8	18.1	34.0	20.2	36.4	15.6

No information supplied.

TABLE 1B.18
INSTALLED NET CAPABILITY BY TYPE OF FUEL - MW
AEP REGION

Winter Capability											
Electric Region AEP + BUPT	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	L.C.	Convent.	Pumped Storage	
1980	2,150	17,080		18					232	560	20,031
% Total	10.7	85.3		0.1					1.1	2.8	100
1981	2,150	172,20		18					263	560	20,211
% Total	10.6	85.2		0.1					1.3	2.8	100
1982	2,150	17220		18					263	560	20,211
% Total	10.6	85.2		0.1					1.3	2.8	100
1983	2,150	18,520		18					263	560	21,511
% Total	10.0	86.1		0.1					1.2	2.6	100.0
1984	2,150	19,820		18					263	560	22,811
% Total	9.4	86.9		0.1					1.2	2.4	100.0
1985	2,150	19,820		18					303	560	22,851
% Total	9.4	86.7		0.1					1.3	2.5	100.0
1986	2,150	21,120		18					303	560	24,151
% Total	8.9	87.4		0.1					1.3	2.3	100.0
1987	2,150	21,120		18					303	560	24,151
% Total	8.9	87.4		0.1					1.3	2.3	100.0
1988	2,150	22,420		18					303	560	25,451
% Total	8.4	88.1		0.1					1.2	2.2	100
1989	2,150	22,420		18					303	560	25,451
% Total	8.4	88.1		0.1					1.2	2.2	100.0

TABLE 1B.19
MAJOR GENERATING CAPABILITY INSTALLATION AND (REMOVALS)
AEP REGION

<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type</u>	<u>Net Summer Capability</u>	<u>In Service Date April 79 "383" Report (MW)</u>	<u>In Service Date April 80 "411" Report</u>
AEP	Smith Mt. #3	PS	H	100	10/79	2/80 *
AEP	Mountaineer #1	St	Coal	1,300	12/80	12/80
AEP	Racine	CH	H	40	12/81	12/81
AEP	Rockport #1	St	Coal	1,300	6/83	6/83 ^{1/}
AEP	Rockport #2	St	Coal	1,300	12/84	12/84 ^{2/}
AEP	Gallipolis	CH	H	40	7/85	7/85
AEP	Lewis Co. #1	St	Coal	1,300	12/86	12/86 ^{3/}
AEP	Lewis Co. #2	St	Coal	1,300	12/88	6/88 ^{4/}

No. Installation and Removals 82, 87, 89

The following changes were reported after the 1980 ERA 411 report was finalized.

1/ Rescheduled for 12/84

2/ Rescheduled for 6/86

3/ Rescheduled for 12/88

4/ Rescheduled for 6/90

* Delayed until 1981

Allegheny Power System (APS)

Historical Perspective

Allegheny Power System includes the southwestern corner and northcentral portions of Pennsylvania, about 50% of the northern portion of West Virginia, the western portion of Maryland and a small portion of northwestern Virginia. The Allegheny Power System, Inc. is the parent company for this integrated electric system comprising the properties of the Monongahila Power Company, the Potomac Edison Company, West Penn Power Company, and their subsidiaries. As such, it is the owner of the operating companies in the System and is the vehicle through which equity capital for the System is obtained. The integrated operation of APS permits economic and other advantages in matters such as: planning of generating and transmission facilities; exchange of technical knowhow; experience and information; uniformity of practice in construction; emergency and economic power exchanges; the scheduling of spinning reserve and maintenance scheduling.

In 1978 the three operating companies served 1,084,000 customers in Pennsylvania, Maryland, West Virginia, and Virginia, of which 967,000 were residential 101,000 were commercial and 16,000 were industrial customers.

The three companies are heavily interconnected through 500KV, 345KV and 230KV transmission lines. There are similar interconnections with other systems in ECAR and also with General Public Utilities, Baltimore Gas & Electric Company, and Potomac Electric Power Company in the MAAC Council and with Virginia Electric Power Company in SERC Council.

APS has historically been a winter peaking region. Table 1A.1 shows the region's summer and winter peaks for the period 1977-1979.

TABLE 1A.1

HISTORICAL PEAK DEMAND-MW
ALLEGHENY POWER SYSTEM REGION

<u>Year</u>	<u>Summer</u>			<u>Winter</u>		
	<u>June</u>	<u>July</u>	<u>August</u>	<u>December</u>	<u>January</u>	<u>February</u>
1977	4139	4524	<u>4539</u>	4883	<u>5174</u>	4937
1978	4362	4575	<u>4632</u>	4921	<u>5331</u>	<u>5335</u>
1979	4378	4621	<u>4676</u>	5221	5263	<u>5272</u>

Underline indicates Seasonal Peak

The summer peak demands are dependent upon climatic conditions and are especially sensitive to temperature/humidity. Usually the peak will occur in July or August. The winter peak can occur in any of the winter months depending on the combination of weather and economic activities in the region.

Table 1A.2 shows the capacity out-of-service due to scheduled maintenance for each summer and winter period and also the unavailable capacity due to forced outages.

TABLE 1A.2
SCHEDULED MAINTENANCE AND UNAVAILABLE CAPABILITIES
ALLEGHENY POWER SYSTEM REGION

Year	Summer			Winter		
	Scheduled Maintenance (MW)	Forced Outages (MW)	Total Capacity Unavailable (MW)	Scheduled Maintenance (MW)	Forced Outages (MW)	Total Capacity Unavailable (MW)
1977	596	947	1,543	1,195	3,359	4,554
1978	500	1,685	2,185	0	1,308	1,308
1979	669	1,834	2,503	186	1,987	2,173

The capacity unavailable for reasons other than scheduled maintenance in 1977-1979 varied from 15-27% of the planned capacity in summer and from 20-52% in winter.

The reserve margins for the 1977-1979 period are shown on Table 1A.3. These values include the effects of scheduled maintenance and forced outages on the reserve margins. The "total capability" shown in Table 1A.3 is the "planned capability" plus the net of all capacity purchases and sales.

TABLE 1A.3
HISTORICAL SEASONAL RESERVES
ALLEGHENY POWER SYSTEM REGION

Year	<u>Summer</u>						
	Peak Demand (MW)	Total Capability (MW)	Total Reserve %	Available Capability (MW)	Reserve After Maintenance %	Available Capability (MW)	Actual Reserve %
1977	4,539	5,890	29.8	5,294	16.6	4,347	(4.2)
1978	4,632	6,153	32.8	5,653	22.0	3,968	(14.3)
1979	4,676	6,726	43.8	6,057	29.5	4,223	(9.7)

<u>Winter</u>							
1977	5,174	6,378	23.3	5,183	0.1	1,824	(64.7)
1978	5,335	6,367	19.3	6,367	19.3	5,059	(5.2)
1979	5,272	7,247	37.4	7,061	33.9	5,074	(3.8)

() Indicates negative reserves

Reserve after maintenance appeared to have been adequate, however, large amounts of forced outages caused actual reserve to be negative during this period. However, the situation appears to be improving. The critical condition during winter 1977/1978 was precipitated by the coal strike and a high number of forced outages. Fortunately, APS had adequate interconnections with neighboring utilities and was able to secure short-term purchases and emergency transfers to cover capacity shortages.

Listed below are annual load and energy requirements for the 1977-79 period.

TABLE 1A.4
HISTORICAL ENERGY, PEAKS AND LOAD FACTORS
ALLEGHENY POWER SYSTEM REGION

Year	<u>Energy Requirements</u>		<u>Summer Demand</u>		<u>Winter Demand</u>		Annual Load Factor
	(Gwh)	Growth-(%)	(MW)	Growth-(%)	(MW)	Growth-(%)	
1977	29,551	-	4,539	-	5,174	-	65.2
1978	30,166	2.1	4,632	2.0	5,335	3.1	64.6
1979	31,813	5.5	4,676	0.9	5,272	(1.2)	68.9
% Growth 1977-79		3.8		1.5		0.9	

Energy requirements over the 1977/1979 period have grown at a compound rate of 3.8%, this is a higher rate than most other regions in ECAR. This is the result of the APS diversity in sales and is indicative of economic stability in their service area. Peak demand growth rates were considerably lower than their traditional patterns. This is due in part to conservation techniques and the increased cost of energy.

Current Perspective

The projected 1980 summer and winter demands are shown below.

TABLE 1A.5

PROJECTED 1980 SEASONAL PEAK DEMAND-MW
ALLEGHENY POWER SYSTEM REGION

<u>Summer</u>			<u>Winter</u>		
<u>June</u>	<u>July</u>	<u>August</u>	<u>December</u>	<u>January</u>	<u>February</u>
4,488	4,833	<u>4,868</u>	5,743	<u>5,933</u>	5,823

Underline indicates seasonal peak

The 1980 summer and winter demands are projected to occur in August and January, respectively. This is consistent with previous occurrences. However the peak may still occur in any month of the particular season depending on economic and climatic conditions.

The extremely high rate of growth (12.5%) between the 1979/80 and 1980/81 winter peak demand is probably due to an overestimation of the 1979/80 winter peak before the fact. There is a difference of 271 MW between forecasted 1979/80 and the actual winter peak. If indeed the 1980/81 forecasted winter peak is inflated due to this forecast error, reserve margins would increase throughout the 1980-1989 period.

The summer demand is projected to be 22% less than the winter demand, which affords the opportunity for the performance of scheduled maintenance.

The 1980 winter planned capability in the APS region is estimated to be 7,671 MW and the winter coincident peak demand is projected to be 5,933 MW. After adjustment for receipts and deliveries, total reserve is 2,142 MW or 36.1%.

In the ECAR ERA-411 report for the (1980-1989) period, APS does not list inoperable capability for either scheduled maintenance or possible forced outages. However, ECAR provides an indication of planned maintenance for the entire region in the ERA 411 report. This estimate is based on the level of planned maintenance that is currently projected for the peak demand periods during the upcoming summer and winter seasons, i.e., five percent of total planned capability during the winter of 1980/81.

The following table indicates forced outage rates experienced by APS.

TABLE 1A.6

FORCED OUTAGE RATES
ALLEGHENY POWER SYSTEM REGION

<u>Year</u>	<u>%</u>
1976 -	5.84
1977 -	5.49
1978 -	16.80
1979 -	19.01

Trends indicates a dramatic increase in forced outage rates on the APS system during 1978 and 1979 as a result of persistent and lengthy outages of the large units on the system. The units at Harrison (3 units - 640 MW each) and at Hatfield's Ferry (3 units - 555 MW each) in total represent over 50% of the APS system capability. At times during the 1978-1979 period, three units were out concurrently at these facilities. Some single units at these facilities were out for periods as long as six months. In the first quarter of 1980, the high forced outage rate continues with units at these facilities still experiencing difficulties. No single problem is evident, but rather a series of unrelated occurrences.

The summer and winter 1980 reserve margins for the electric region are shown below.

TABLE 1A.7

RESERVE MARGINS
ALLEGHENY POWER SYSTEM REGION

<u>Electric Region</u>	<u>1980 Summer Reserve Margin</u>						<u>1980 Winter Reserve Margin</u>					
	<u>Planned</u>		<u>Total</u>		<u>After</u>		<u>Planned</u>		<u>Total</u>		<u>After</u>	
	<u>Reserves</u>	<u>Reserves</u>	<u>Reserves</u>	<u>Reserves</u>	<u>Maintenance*</u>	<u>Maintenance*</u>	<u>Reserves</u>	<u>Reserves</u>	<u>Reserves</u>	<u>Reserves</u>	<u>Maintenance*</u>	<u>Maintenance*</u>
	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>
APS	1954	40.1	1790	36.8	1449	29.8	1738	29.3	2142	36.1	1758	29.6

* 5% of total planned capability assumed from ECAR-ERA-411 Report for scheduled maintenance.

The reserve margins shown above have not been adjusted for unscheduled outages since the amount of these outages are generally unknown. However, these outages have been running as high as 19%. As long as unscheduled outages do not exceed about 20-25% of the seasonal capability, the resultant available reserves should be a positive number.

The systems in APS region are governed by ECAR Document No.2 Daily Operating Reserve agreement which specifies that each system, as a minimum must provide, (1) an amount of reserve equal to three percent of the maximum 60-minute integrated clock hour internal load predicted for the day to provide for load regulation and for system frequency regulation. This portion of the operating reserve shall be spinning reserve within the control area of the system; (2) An amount of reserve equal to three percent of the maximum 60-minute integrated clock hour native load predicted for the day times the system's allocating constant to provide for protection against an unexpected loss of generation. This portion of the operating reserve may be allocated in any desired combination with the following limits and is fully applicable within ten minutes:

- 1) 0-100 percent spinning reserves.
- 2) 0-100 percent non-spinning reserves either interruptible or quick-start.
- 3) 0-100 percent prescheduled assistance from another system(s).

The winter 1980/81 capability of the generating facilities installed in the APS region will be 7671 MW. The capability breakdown by fuel type is shown below.

TABLE 1A.8

1980/81 WINTER PLANNED CAPABILITY
ALLEGHENY POWER SYSTEM REGION

<u>Electric</u> <u>Region</u>	(Steam) <u>Nuc</u> <u>(MW)</u>	(Steam) <u>Coal</u> <u>(MW)</u>	(Steam) <u>Oil</u> <u>(MW)</u>	(Conv.) <u>Hydro</u> <u>(MW)</u>	<u>Total</u> <u>Capability</u> <u>(MW)</u>
AP	0	7123	486	62	7,671
% Total		92.9	6.3	0.8	100.0

Almost 93% of the current capacity is coal-fired steam capacity; 6%, oil-fired steam; and 1% hydroelectric. There are no nuclear facilities installed in the Region and hydroelectric generation is an insignificant portion of the total. There is only one coal-fired unit scheduled to be placed in service during the 1980, Pleasants #2 with a rating of 626 MW, in October.

The projected 1980 energy requirements, summer and winter demands and annual load factor for the region are shown in Table 1A.9.

TABLE 1A.9

1980 ENERGY REQUIREMENTS, PEAK DEMAND AND LOAD FACTOR
ALLEGHENY POWER SYSTEM REGION

	<u>Energy Requirements (Gwh)</u>	<u>Summer Demand (MW)</u>	<u>Winter Demand (MW)</u>	<u>Annual L.F. (%)</u>
	33,600	4,868	5,933	66.8
% Growth 1980/89	5.6	4.1	12.5	

The 1980 estimated energy requirements and peak demands are projected to grow at considerably higher rates than they did during the 1977-79 period.

Delays of future critical bulk power transmission facilities that will not be in service when needed is required to be reported under Item 5-C of the ERA 411 report. There are no transmission lines in this category reported by APS in the April 1, 1980 ECAR report.

Future Perspective

The range of total reserve for APS for the periods 1981-1985 and 1986-1989 are shown in Table 1A.10.

TABLE 1A.10

PROJECTED APS TOTAL RESERVE - %
ALLEGHENY POWER SYSTEM REGION

<u>1981 - 1985</u>		<u>1986 - 1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
15.0-39.2	7.2-27.4	22.1-41.4	13.6-25.3

As shown in the Table, the total reserve vary from a low of 7.2% in the winter 1985-86 to a high of 41.4% in the summer of 1989. As indicated in Table 1A.20 for the winter peak, for the years 1984, 85, and 86 APS could have difficulty meeting its obligations. Should the scheduled maintenance run as indicated previously, at 5% of planned capability the reserve after maintenance would be as little as 150 MW or less than 2%. This leaves very little margin for unscheduled outages or other capability unavailable.

Shown below are the projected growth rates of demand and capability for each period and the overall rates for 1981-89.

TABLE 1A.11

PROJECTED GROWTH RATES - %
ALLEGHENY POWER SYSTEM REGION

	<u>Summer</u> <u>Peak Demand</u>	<u>Winter</u> <u>Peak Demand</u>	<u>Energy</u> <u>Requirement</u>
1981-1985	4.5	4.4	4.2
1986-1989	3.9	4.5	4.0
1981-1989	4.3	4.4	4.1

The summer peak demands are projected to increase at a compound rate of growth of 4.5% during 1981-1985 period, 3.9% during 1986-1989 period and at 4.3% during 1981-1989 period. The rates are considerably higher than the summer 1977-1979 growth of 1.5%.

No new capacity is projected for the 1981-1985 period. Winter capability is expected to increase by 6.3% in the 1986-89 period and summer capability is expected to increase by 9.2% during this period. For the 1981-89 time frame, winter and summer capability increases are about equal to demand projection increases of 4.3% and 4.4%.

The energy requirements are projected to grow 4.2% from 1981-85, 4.0% from 1986-1989, and 4.1% for the overall period 1981-1989. These rates of growth are similar to the past trends which indicate a balance of economic activities.

The winter capability of units installed in the Region for the period 1980-1989 is listed by type of fuel in Table 1A.20. Major generating unit additions during the period are given in Table 1A.21. The percentages of each type of capacity for the target years 1980, 1984 and 1989 are indicated below.

TABLE 1A.12

INSTALLED GENERATING CAPABILITY BY TYPE OF FUEL - %
WINTER CAPABILITY
ALLEGHENY POWER SYSTEM REGION

	<u>Coal</u> <u>Steam</u>	<u>Oil</u> <u>Steam</u>	<u>Hydro</u> <u>Conv.</u>	<u>Pumped</u> <u>Storage</u>
1980	92.9	6.3	0.8	0
1984	92.9	6.3	0.8	0
1989	85.3	4.6	0.6	9.5

Currently, coal is the primary fuel for about 93% of the planned capability of the region. This percentage is projected to decrease to 85% by 1989, due to the proposed installation of the 1000 MW Davis Pumped Storage plant. Two units (250 MW each) are to be installed in 1986 and two units (250 MW each) in 1987.

Only one additional plant is projected for the Region, a three-unit coal-fired plant - Lower Armstrong (630 MW each). The units are scheduled for installation in 1986, 1987, and 1988. The installation of these units appear to be critical in meeting the APS obligations. If the first 630 MW unit is not on line to meet the 1986-87 winter peak demand, the peak demand of 7,738 MW will reduce the planned reserve from 13.6% to 5.5%. This assumes that the Davis Pumped Storage Plant, whose construction is highly speculative, will not be on line. Even if the two Davis units (500 MW) scheduled for 1986 were in service the situation would still be precarious. It appears that under this situation APS, which shows no purchases from 1985 to 1989, may have to turn to capacity imports from neighboring systems.

The most recent ECAR appraisal studies on the APS transmission line status for Summer 1979 and Winter 1979-80 indicates that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

TABLE 1A.13

EMERGENCY TRANSFER CAPABILITY-MW
ALLEGHENY POWER SUPPLY REGION

<u>Transfer Parties</u>	<u>Summer 1979</u>	<u>Winter 1979-80</u>
ECAR to MAAC	3300+	3300+
ECAR to NPCC (NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC (VACAR)	1250	1900*
ECAR from MAAC	2450	3300+
ECAR from NPCC (NYPP)	3300+	2900
ECAR from MAIN	4000+	3800+
ECAR from SERC (TVA)	2000	2100
ECAR from SERC (VACAR)	2700	2950*

* Energy Transfer Capability Values determined with established operating procedures in effect.

Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed due to regulatory or financial reasons would necessitate appropriate short term operating procedures to be developed in order to maintain the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, are as follows:

TABLE 1A.14

SUMMER 1984 EMERGENCY TRANSFER CAPABILITY - MW
ALLEGHENY POWER SUPPLY REGION

<u>Transfer Parties</u>	<u>MW</u>	<u>Transfer Parties</u>	<u>MW</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC	2900
ECAR to MAIN	2900	ECAR from MAIN	4000+
ECAR to SERC (TVA)	2500	ECAR from SERC (TVA)	3200
ECAR to SERC (VACAR)	2250	ECAR from SERC (VACAR)	5500+

Table 1A.15 shows a list of proposed bulk power lines to be constructed by APS. It includes internal transmission as well as interconnections with other utilities. Many of these interconnection will become critical, since APS's low reserve margins in the mid-1980s may make them heavily dependent on capacity imports.

Table 1A.15

PROPOSED BULE POWER LINES
ALLEGHENY POWER SYSTEM (APS)

<u>Line Ownership</u>	<u>Terminal</u>	<u>Line Length Miles</u>	<u>Planned Service Date</u>	<u>Nominal Voltage in KV</u>		<u>Remarks</u>
				<u>OPER</u>	<u>DSGN</u>	
<u>Allegheny Power System</u>						
APS	Monocacy / Ringgold	14.0	Sept 80	230	230	
APS	Monocacy / Doubs	13.0	Dec 81	230	230	
APS	Elko / Carbon Center	6.0	Dec 81	230	230	
APS	Bucklodge / Montgomery	8.5	Dec 82	230	230	
APS	Harrison / Yukon	64.0	Jun 83	500	500	Total 94.0 MI., 30.0 Mi. Installed in 1978
APS	Prexy / Harrison-Yukon	0.0	Jun 83	500	500	Loop into Prexy
APS	Montgomery / Doubs-Monocacy	13.0	Dec 83	230	230	Convert 138 KV Line for 230 KV operation
APS	Black Oak / Hatfield-Edington	0.0	Dec 84	500	500	Loop into Black Oak
APS	Montgomery / Mt. Airy	15.0	Dec 84	230	230	
APS	Shingletown / Milesburg	14.0	Dec 84	230	230	
APS	Lower Armstrong / Cabot-Keystone IPJM)	20.0	Oct 85	500	500	Loop into Lower Armstrong
ASP	Davis / Pruntytown-Mt. Storm (VEPCO)	19.0	Nov 85	500	500	Loop into Davis
APS	Monocacy / Mt. Airy	13.0	Dec 85	230	230	
APS	Cabot / Lower Armstrong	16.0	Jan 87	500	500	
APS	Elko / Carbon Center	6.0	Dec 88	230	230	
APS	Harrison / Bucklodge	40.0	Dec 88	500	500	

XI.1.40

Table 1A.15

PROPOSED BULK POWER LINES
ALLEGHENY POWER SYSTEM (APS)

Line Ownership		Terminals	Line Length Miles	Planned Service Date	Nominal Voltage in KV	
					OPER	DSGN
Interconnections						
APS	PJM	Milesburg / Shawville-East Towanda	31.0	Dec 83	230	230
APS	VEPCO	Black Oak / Mt. Storm	30.0	Jun 87	500	500
APS	PJM	Bucklodge / Dickerson-Quince Orchard	0.0	Dec 80	230	230
APS	PJM	Elko / Elso Tap	3.0	Dec 80	230	230
APS	VEPCO	Meadowbrook / Mt. Storm-Morrisville	0.0	Dec 82	500	500

Table 1A.16

HISTORICAL CAPABILITY AND RESERVE MARGINS
ALLEGHENY POWER SYSTEM REGION

	<u>1977 Summer</u>	<u>1977/1978 Winter</u>	<u>1978 Summer</u>	<u>1978/1979 Winter</u>
(1) Planned Capability (MW)	6,203	6,428	6,203	6,417
(2) Peak Demand (MW)	4,539	5,174	4,632	5,335
(3) Planned Reserve (MW) (1-2)	1,664	1,254	1,571	1,082
(4) Planned Reserve (%) (3-2) x 100	36.7	24.2	33.9	20.3
(5) Net Transactions <u>1/</u> (MW)	(313) <u>2/</u>	(50) <u>2/</u>	(50) <u>2/</u>	(50) <u>2/</u>
(6) Total Capability (MW) (1+5)	5,890	6,378	6,153	6,367
(7) Total Reserve (MW) (6-2)	1,351	1,204	1,521	1,032
(8) Total Reserve (%) (7-2) x 100	29.8	23.3	32.8	19.3
(9) Scheduled Maintenance (MW)	596	1,195	500	0
(10) Capability after Maintenance (MW) (6-9)	5,294	5,183	5,653	6,367
(11) Reserve after Maintenance (MW) (10-2)	755	9	1,021	1,032
(12) Reserve after Maintenance (%) (11-2) x 100	16.6	0.2	22.0	19.3
(13) Inoperable Capability (MW)	0	0	0	0
(14) Available Capability (MW) (10-13)	5,294	5,183	5,653	6,367
(15) Available Reserve (MW) (14-2)	755	9	1,021	1,032
(16) Available Reserve (%) (15-2) x 100	16.6	0.2	22.0	19.3
(17) Forced Outages (F.O.) (MW)	947	3,359	1,685	1,308
(18) Available Capability after F.O. (MW) (14-17)	4,347	1,824	3,968	5,059
(19) Actual Reserve (MW) (18-2)	(192) <u>2/</u>	(3,350) <u>2/</u>	(664) <u>2/</u>	(276) <u>2/</u>
(20) Actual Reserve (%) (19-2) x 100	(4.2) <u>2/</u>	(64.7) <u>2/</u>	(14.3) <u>2/</u>	(5.2) <u>2/</u>

1/ Net Transactions = Purchases - Sales

2/ () denotes negative number

Table 1A.17

HISTORICAL AND CURRENT CAPABILITIES AND RESERVE MARGINS
ALLEGHENY POWER SYSTEM REGION

	<u>1979 Summer</u>	<u>1979/1980 Winter</u>	<u>1980 Summer</u>	<u>1980/1981 Winter</u>
(1) Planned Capability (MW)	5,776	6,997	6,822	7,671
(2) Peak Demand (MW)	4,676	5,272	4,868	5,933
(3) Planned Reserve (MW) (1-2)	2,100	1,725	1,954	1,738
(4) Planned Reserve (%) (3-2) x 100	44.9	32.7	40.1	29.3
(5) Net Transactions <u>1/</u> (MW)	(50) <u>2/</u>	250	(164) <u>2/</u>	404
(6) Total Capability (MW) (1+5)	6,726	7,247	6,658	8,075
(7) Total Reserve (MW) (6-2)	2,050	1,975	1,790	2,142
(8) Total Reserve (%) (7-2) x 100	43.8	37.5	36.8	36.1
(9) Scheduled Maintenance (MW)	669	186	341	384
(10) Capability after Maintenance (MW) (6-9)	6,057	7,061	6,317	7,691
(11) Reserve after Maintenance (MW) (10-2)	1,381	1,789	1,449	1,758
(12) Reserve after Maintenance (%) (11-2) x 100	29.5	33.9	29.8	29.6
(13) Inoperable Capability (MW)	0	0	0	0
(14) Available Capability (MW) (10-13)	6,057	7,061	6,317	7,691
(15) Available Reserve (MW) (14-2)	1,381	1,789	1,449	1,758
(16) Available Reserve (%) (15-2) x 100	29.5	33.9	29.8	29.6
(17) Forced Outages (F.O.) (MW)	1,834	1,987	3/	3/
(18) Available Capability after F.O. (MW) (14-17)	4,223	5,074	6,317	7,691
(19) Actual Reserve (MW) (18-2)	(453) <u>2/</u>	(198) <u>2/</u>	1,449	1,758
(20) Actual Reserve (%) (19-2) x 100	(9.7) <u>2/</u>	(3.8) <u>2/</u>	29.8	29.6

1/ Net Transactions = Purchases - Sales

2/ () denotes negative number

FUTURE CAPABILITY AND RESERVE MARGINS 1981-1989
ALLEGHENY POWER SYSTEM REGION

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	7,448	7,671	7,448	7,661	7,438	7,661	7,438	7,661
(2) Peak Demand (MW)	5,208	6,258	5,483	6,513	5,723	6,733	5,908	7,108
(3) Planned Reserve (MW) (1-2)	2,240	1,413	1,965	1,148	1,715	928	1,530	553
(4) Planned Reserve (%) (3-2) x 100	43.0	22.6	35.8	17.6	30.0	13.8	25.9	7.8
(5) Net Transactions ^{1/} (MW)	(200) ^{2/}	300	(300) ^{2/}	300	(300) ^{2/}	300	(300) ^{2/}	300
(6) Total Capability (MW) (1+5)	7,248	7,971	7,148	7,961	7,138	7,961	7,138	7,961
(7) Total Reserve (MW) (6-2)	2,040	1,713	1,665	1,448	1,415	1,228	1,230	853
(8) Total Reserve (%) (7-2) x 100	39.2	27.4	30.4	22.2	24.7	18.2	20.8	12.0
(9) Scheduled Maintenance (MW)	3/	3/	3/	3/	3/	3/	3/	3/
(10) Capability after Maintenance (MW) (6-9)	7,248	7,971	7,148	7,961	7,138	7,961	7,138	7,961
(11) Reserve after Maintenance (MW) (10-2)	2,040	1,713	1,665	1,448	1,415	1,228	1,230	853
(12) Reserve after Maintenance (%) (11-2) x 100	39.2	27.4	30.4	22.2	24.7	18.2	20.8	12.0
(13) Inoperable Capability (MW)	3/	3/	3/	3/	3/	3/	3/	3/
(14) Available Capability (MW) (10-13)	7,248	7,971	7,148	7,961	7,138	7,961	7,138	7,961
(15) Available Reserve (MW) (14-2)	2,040	1,713	1,665	1,448	1,415	1,228	1,230	853
(16) Available Reserve (%) (15-2) x 100	39.2	27.4	30.4	22.2	24.7	18.2	20.8	12.0
(17) Forced Outages (F.O.) (MW)	3/	3/	3/	3/	3/	3/	3/	3/
(18) Available Capability after F.O. (MW) (14-17)	7,248	7,971	7,148	7,961	7,138	7,961	7,138	7,961
(19) Actual Reserve (MW) (18-2)	2,040	1,713	1,665	1,448	1,415	1,228	1,230	853
(20) Actual Reserve (%) (19-2) x 100	39.2	27.4	30.4	22.2	24.7	18.2	20.8	12.0

^{1/} Net Transactions = Purchases - Sales

^{2/} () denotes negative number

^{3/} Information on scheduled maintenance, inoperable capability and forced outages are not available

Table 1A.18

FUTURE CAPABILITY AND RESERVE MARGINS 1981-1989
ALLEGHENY POWER SYSTEM REGION

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	7,438	7,661	7,938	8,791	9,068	9,921	9,698	10,551	10,328	10,551
(2) Peak Demand (MW)	6,208	7,428	6,503	7,738	6,758	8,033	6,963	8,423	7,303	8,823
(3) Planned Reserve (MW) (1-2)	1,230	233	1,435	1,053	2,310	1,888	2,735	2,128	3,025	1,728
(4) Planned Reserve (%) (3-2) x 100	19.8	3.1	22.1	13.6	34.2	23.5	39.3	25.3	41.4	19.6
(5) Net Transactions ^{1/} (MW)	(300) ^{2/}	300	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}
(6) Total Capability (MW) (1+5)	7,138	7,961	7,938	8,791	9,068	9,921	9,698	10,551	10,328	10,551
(7) Total Reserve (MW) (6-2)	930	533	1,435	1,053	2,310	1,888	2,735	2,128	3,025	1,728
(8) Total Reserve (%) (7-2) x 100	15.0	7.2	22.1	13.6	34.2	23.5	39.3	25.3	41.4	19.6
(9) Scheduled Maintenance (MW)	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}
(10) Capability after Maintenance (MW) (6-9)	7,138	7,961	7,938	8,791	9,068	9,921	9,698	10,551	10,328	10,551
(11) Reserve after Maintenance (MW) (10-2)	930	533	1,435	1,053	2,310	1,888	2,735	2,128	3,025	1,728
(12) Reserve after Maintenance (%) (11-2) x 100	15.0	7.2	22.1	13.6	34.2	23.5	39.3	25.3	41.4	19.6
(13) Inoperable Capability (MW)	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}
(14) Available Capability (MW) (10-13)	7,138	7,961	7,938	8,791	9,068	9,921	9,698	10,551	10,328	10,551
(15) Available Reserve (MW) (14-2)	930	533	1,435	1,053	2,310	1,888	2,735	2,128	3,025	1,728
(16) Available Reserve (%) (15-2) x 100	15.0	7.2	22.1	13.6	34.2	23.5	39.3	25.3	41.4	19.6
(17) Forced Outages (F.O.) (MW)	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}	^{3/}
(18) Available Capability after F.O. (MW) (14-17)	7,138	7,961	7,938	8,791	9,068	9,921	9,698	10,551	10,328	10,551
(19) Actual Reserve (MW) (18-2)	930	533	1,435	1,053	2,310	1,888	2,735	2,128	3,025	1,728
(20) Actual Reserve (%) (19-2) x 100	15.0	7.2	22.1	13.6	34.2	23.5	39.3	25.3	41.4	19.6

^{1/} Net Transactions = Purchases - Sales

^{2/} () denotes negative number

^{3/} Information on net transactions, scheduled maintenance, inoperable capability, and forced outages are not available

Table 1A.19
ACTUAL AND PROJECTED ENERGY, DEMAND AND CAPABILITY
ALLEGHENY POWER SYSTEM (APS)

Electric Region (APS)	Energy Requirements		Summer Demand		Winter Demand		Annual Load Factor %	Summer Capability		Winter Capability	
	(MWh)	Growth %	(MW)	Growth %	(MW)	Growth %		(MW)	Growth %	(MW)	Growth %
1977	29,551,313		4,539	-	5,174	-	67.1	6,203	-	6,428	-
1978	30,166,454	2.1	4,632	2.0	5,335	3.1	66.6	6,203	0	6,417	(0.2)
1979	31,813,206	5.5	4,676	0.9	5,272	(1.2)	68.1	6,776	9.2	6,997	9.0
Growth 77-79	-	3.8	-	1.5	-	0.9	-	-	4.5	-	4.3
1980	33,600,000	5.6	4,868	4.1	5,933	12.5	66.8	6,822	0.7	7,671	9.6
1981	35,700,000	6.3	5,208	7.0	6,258	5.5	65.1	7,448	9.2	7,671	0
1982	37,200,000	4.2	5,483	5.3	6,513	4.1	65.2*	7,448	0	7,661	(0.1)
1983	38,700,000	4.0	5,723	4.4	6,733	3.4	65.6*	7,438	(0.1)	7,661	0
1984	40,400,000	4.4	5,908	3.2	7,108	5.5	64.9*	7,438	0	7,661	0
1985	42,100,000	4.2	6,208	5.0	7,428	4.5	64.7*	7,438	0	7,661	0
Growth 81-85	-	4.2	-	4.5	-	4.4	-	-	0	-	0
1986	43,800,000	4.0	6,503	4.7	7,738	4.1	64.6*	7,938	6.7	8,791	14.8
1987	45,400,000	3.7	6,758	3.9	8,033	3.8	64.5*	9,068	14.2	9,921	12.9
1988	47,200,000	4.0	6,963	3.0	8,423	4.8	64.0*	9,698	6.9	10,551	6.4
1989	49,200,000	4.2	7,303	4.9	8,823	4.7	63.7*	10,328	6.5	10,551	0
Growth 86-89	-	4.0	-	4.0	-	4.4	-	-	9.2	-	6.3
Growth 81-89	-	4.1	-	4.3	-	4.4	-	-	4.2	-	4.1

* Based on winter peak rather than annual peak.

Table 1A.20
INSTALLED NET CAPABILITY BY TYPE OF FUEL - MW
ALLEGHENY POWER SYSTEM (APS)

Winter Capability - MW											
Electric Region APS	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	L.C.	Convent.	Pumped Storage	
1980	-	7,123	486	-	-	-	-	-	62	-	7,671
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1981	-	7,123	486	-	-	-	-	-	62	-	7,671
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1982	-	7,113	486	-	-	-	-	-	62	-	7,661
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1983	-	7,113	486	-	-	-	-	-	62	-	7,661
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1984	-	7,113	486	-	-	-	-	-	62	-	7,661
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1985	-	7,113	486	-	-	-	-	-	62	-	7,661
% Total	-	92.9	6.3	-	-	-	-	-	.8	-	100.0
1986	-	7,743	486	-	-	-	-	-	62	500	8,791
% Total	-	88.1	5.5	-	-	-	-	-	.7	5.7	100.0
1987	-	8,373	486	-	-	-	-	-	62	100.0	9,921
% Total	-	84.4	4.9	-	-	-	-	-	.6	10.1	100.0
1988	-	9,003	486	-	-	-	-	-	62	1,000	10,551
% Total	-	85.3	4.6	-	-	-	-	-	.6	9.5	100.0
1989	-	9,003	486	-	-	-	-	-	62	1,000	10,551
% Total	-	85.3	4.6	-	-	-	-	-	.6	9.5	100.0

Table 1A.21

MAJOR GENERATING UNIT ADDITIONS AND REMOVALS

ALLEGHENY POWER SYSTEM (APS)

<u>E.R.</u>	<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type</u>	<u>Net Summer Capability</u>	<u>In Service Date</u>	<u>In Service Date</u>	
						<u>April 79 "183" Report</u> (MW)	<u>April 80 "411" Report</u>	
1	APS	Davis #1	PS	H	250	3/86	3/86	u ^{1/}
1	APS	Davis #2	PS	H	250	6/86	6/86	u
1	APS	Davis #3	PS	H	250	3/87	3/87	u
1	APS	Davis #4	PS	H	250	6/87	6/87	u
1	APS	Lower Armstrong #1	St	Coal	630	5/84	6/86	p ^{2/}
1	APS	Lower Armstrong #2	St	Coal	630	3/85	9/87	p
1	APS	Lower Armstrong #3	St	Coal	630	3/86	9/88	p
1	APS	Pleasants #2	St	Coal	626	3/80	10/80	u

NOTE: No installations or removals during 1981-1985 and 1989

^{1/} u - Under construction, less than 50% complete

^{2/} p - Planned for installation but not (utility) authorized

Central Area Power Coordination Group (CAPCO)

ELECTRIC REGION 13

Historical Perspective

Region 13 includes the Central Area Power Coordination Group and the Cleveland Municipal System.

The Central Area Power Coordination Group (CAPCO) is a coordinating group with activities in two principal areas: planning and operation. CAPCO was originally formed in 1964, and now consists of five major investor-owned electric utilities providing service in northern Ohio and western Pennsylvania. The five member systems are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company.

The CAPCO organization is headed by an Executive Committee which is responsible for basic policy and development of new opportunities for mutual economic and reliability benefits.

Practices in the Planning and Development of Facilities have included coordinated; (1) load forecasts, (2) planning for reserves, (3) system stability studies, (4) joint or staggered participation in facilities development, and (5) pooling arrangements. Operating Practices have included coordination of; (1) capacity and energy exchange, (2) reserves including spinning reserves, (3) maintenance, and (4) economic dispatch including description of control facilities. Each of the five CAPCO companies has its own system dispatch center. Under the terms of the CAPCO Basic Operating Agreement the members of CAPCO can purchase or interchange power and energy, economy exchange, and unit capacity and energy from the other members of the pool. The sales or exchanges are subject to the mutual consent of the buyer and seller, but if a transaction is made it must be in accordance with the schedules set forth in the Basic Operating Agreement. The members of CAPCO are also free to buy, sell, or exchange power and energy with utilities outside of CAPCO.

A utility not included in CAPCO but within the CAPCO region is the Division of Light and Power of the City of Cleveland. It is a liaison member of ECAR and included in subsequent tables.

In 1978, the utilities in the CAPCO region served almost 2,489,000 customers, of which 2,230,000 were residential, 219,000 commercial, 13,000 were industrial, and 27,000 others. The CAPCO Companies, although widely dispersed, are highly interconnected internally and with other ECAR systems at 345 KV and 138 KV. Since the CAPCO region is in the extreme northeast corner of ECAR, its only interconnections with other regions are to the east, with utilities in MAAC.

The CAPCO region has historically been a summer peaking area. Shown below are the region's summer and winter peaks for the period 1977-1979.

Table 1C.1

Historical Peak Demands - MW
CAPCO REGION

	<u>Summer</u>			<u>Winter</u>		
	<u>June</u>	<u>July</u>	<u>August</u>	<u>December</u>	<u>January</u>	<u>February</u>
1977	10280	<u>11384</u>	10856	10260	<u>10347</u>	9909
1978	10873	<u>11194</u>	10667	10254	<u>10841</u>	10732
1979	10294	<u>10809</u>	10777	10428	<u>10442</u>	10304

NOTE: underline indicates seasonal peak.

The summer peak demands are usually dependent on climate conditions and are temperature/humidity sensitive. However, in the three reported years the peak demand has occurred in the month of July.

The winter peak during the 1977-1979 period occurred in January. These peaks were 3 to 9 percent lower than the corresponding summer peaks, a normal situation.

The following table shows generating capacity down for scheduled maintenance performed each period and also the capability unavailable due to forced unit and partial unit outages.

Table 1C.2

Scheduled Maintenance and Unavailable Capabilities - (MW)
CAPCO REGION

	<u>Summer</u>			<u>Winter</u>		
	<u>SCHEDULED</u> <u>MAINTENANCE</u>	<u>OTHER</u> <u>UNAVAIL-ABLE</u>	<u>TOTAL</u> <u>UNAVAIL-ABLE</u>	<u>SCHEDULED</u> <u>MAINTENANCE</u>	<u>OTHER</u> <u>UNAVAIL-ABLE</u>	<u>TOTAL</u> <u>UNAVAIL-ABLE</u>
1977	414	2002	2416	656	5118	5774
1978	1005	3742	4747	1075	5622	6997
1979	830	3808	4638	2353	2227	4580

The percentage of planned capability that was unavailable for reasons other than scheduled maintenance varied from 14 to 25 percent during 1977-1979 in the summer and from 14 to 36 percent in the winter.

The reserve margins for the 1977-1979 period are shown below, the table indicating the effects of scheduled maintenance and other outages.

Table 1C.3
Historical Seasonal Reserves
CAPCO REGION

	Peak Demand (MW)	Total Capability (MW)	Total Reserves (%)	Capability After Main- tenance (MW)	Available Reserves (%)	Actual Capability (MW)	Actual Reserves (%)
<u>SUMMER</u>							
1977	11384	13672	20.1	13258	16.5	11256	(1.1)
1978	11194	15118	35.1	14113	26.0	10371	(7.4)
1979	10809	15556	43.9	14726	36.2	10918	1.0
<u>WINTER</u>							
1977	10357	14544	40.6	13888	34.2	8770	(15.2)
1978	10841	15615	44.0	14540	34.1	8918	(17.7)
1979	10442	15434	47.8	13081	25.3	10854	3.9

Available reserve margins were adequate in 1977-1979; however, during the peak periods, large amounts of forced and other outages - especially in 1977 and 1978 - caused actual reserves to fall well below desirable levels. The situation in 1979 improved significantly and available reserves were 1 percent in the summer and rose to 3.9 percent in the winter.

Listed below are annual load and energy requirements for the 1977-1979 period.

Table 1C.4

Historical Energy, Peaks, and Load Factors
CAPCO REGION

	Energy Requirements		Summer Peak Demand		Winter Peak Demand		Annual Load Factor
	(GWh)	(Growth-%)	(MW)	(Growth-%)	(MW)	(Growth-%)	(%)
1977	64570	-	11279	-	10252	-	65.4
1978	64777	0.3	11087	(1.7)	10750	4.9	66.7
1979	65900	1.7	10715	(3.4)	10351	(3.7)	70.2
% Growth 77-79		1.0		(2.6)		0.5	-

Energy requirements over the period 1977-1979 have grown at a modest compound rate of 1 percent. This is lower than most other regions in ECAR. This generally reflects the effects of conservation, and an economic slowdown in this heavily industrialized area. Low peak demand growth was a result of these same conditions plus mild temperatures. Peak demands grew at a lower rate than the energy requirements resulting in an increase in annual system load factors.

Current Perspective

Projected 1980 summer and winter peak demands for the CAPCO region are shown below.

Table 1C.5

Projected 1980 Seasonal Peak Demands - MW
CAPCO REGION

	SUMMER			WINTER	
June	July	August	December	January	February
11159	<u>11434</u>	11378	10627	<u>10904</u>	10614

The 1980 summer planned generating capability for the CAPCO region is estimated to be 14,611 MW and the summer non-coincident peak demand requirements are projected to be 11,434 MW excluding 170 MW of interruptible demand. After adjustments for scheduled receipts and deliveries, total reserves are 3455 MW or 30.2 percent.

In the ECAR ERA-411 report for the future (1980-1989) CAPCO does not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an indication of planned maintenance for the entire region.

The estimate prepared for the ERA-411 report is based on the level of planned maintenance that is currently projected for the periods of heaviest load during the upcoming summer and winter seasons, i.e., five percent of total planned capability during the summer of 1980 and five percent of total planned capability during the winter of 1980/1981.

The summer and winter 1980 reserve margins for the CAPCO Region are shown on Table 1C.6.

Table 1C.6

1980 Reserve Margins*
CAPCO REGION

Summer						Winter					
Planned Reserves		Total Reserves		Available Reserves**		Planned Reserves		Total Reserves		Available Reserves**	
MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
3177	27.8	3455	30.2	2589	22.6	4860	44.6	5030	46.1	4107	37.7

* Based on ERA Form 411

** 5% of total installed capability assumed - from ECAR ERA-411 Report of Scheduled Outages.

The margins shown above have not been adjusted for unscheduled outages of generating equipment since the amounts of these outages are generally unknown ahead of time, but have run as high as 36 percent in 1978. For the forecast period 1980-89, Cleveland Municipal will have 135 MW of coal-fired steam capability unavailable. If unscheduled outages for 1980 are equal to the average outage rates of the 1977-1979 period, 20% of the planned capability during the summer period

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and 25 percent during the winter period, the resultant actual reserves would be deficient by 333 MW, (2.9) percent for the summer peak, but 166 MW or 1.5 percent for the winter peak.

The 1980 summer capability of the planned generating capacity in the CAPCO region will be 14,611 MW. The capacity breakdown by fuel type is shown on Table 1C.7.

Table 1C.7

1980 Summer Capability CAPCO REGION

<u>Nuclear</u>	<u>Coal</u>	<u>Oil</u>			<u>Hydro</u>		<u>Total</u>
<u>Steam</u>	<u>Steam</u>	<u>Steam</u>	<u>CT</u>	<u>IC</u>	<u>Conv.</u>	<u>PS</u>	<u>Capability</u>
1776	11076	672	727	30	0	330	14611
Total 12.1	75.8	4.6	5.0	0.2	0	2.3	100.0

Almost 76 percent of the current capacity within CAPCO is coal-fired steam capacity; 12 percent is nuclear, 5 percent, oil-fired steam, 5 percent, oil-fired combustion turbine and diesels, and 2 percent pumped storage. There are no conventional hydroelectric units in the region. A 780 MW coal-fired steam unit, Mansfield #3, is scheduled for installation in October 1980.

The projected 1980 energy requirements, summer and winter demands, and annual load factors of the region are shown below:

Table 1C.8

1980 Load Requirements CAPCO REGION

	<u>Energy</u>	<u>Summer Peak</u>	<u>Winter Peak</u>	<u>Annual</u>
	<u>Requirements</u>	<u>Demand</u>	<u>Demand</u>	<u>Load Factor</u>
	(GWh)	(MW)	(MW)	(%)
	68390	<u>11434</u>	10904	68.1
% Growth				
1980/79	2.9	5.8	4.4	

The 1980 projected energy requirements are projected to grow at a rate of 2.9 percent which is considerably higher than the rate of growth between 1977-1979 of 1 percent. The 1980 summer peak is expected to increase 5.8 percent over 1979. This will reverse the declining summer demand in the 1977-1979 period. The 1980 winter peak is forecasted to grow by 4.4 percent over 1979. The winter peak has been erratic, at 4.8 percent from 1977-1978 and a decline of 3.7 percent from 1978-1979.

Delays of future critical bulk power transmission facilities that will not be in service when needed, are reported under Item 5-C of the ERA-411 Report. One such line adversely impacting the system was originally scheduled for 1977 but has been delayed. This line is the Mansfield-Juniper 345 kV line, an extension of the existing Mansfield-Hanna 345 kV line, which will complete the third 345 kV interconnection between the Ohio Edison System (Akron area) and the Cleveland Electric Illuminating Company's southern interface.

This line, which was originally scheduled for April 1977 completion, is currently scheduled for June 1980 operation. The delay of this extension to CEI severely restricts their import capability, thus hampering their ability to conduct emergency power and normal economy energy transfers.

The construction on sections of this line has been repeatedly delayed because of local area right-of-way problems and the lack of cooperation by two local municipalities to gain approval on the routing of said line through these areas. A Declaratory Judgement action to resolve the routing controversy is before the Summit County Court of Common Pleas.

Future Perspective

The range of total reserves of the CAPCO region for the periods 1981-1985 and 1986-1989 are shown below.

Table 1C.9

Range of Total Reserves - %

CAPCO REGION

<u>1981 - 1985</u>		<u>1986 - 1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
19.8 - 30.2	30.2 - 39.2	19.3 - 23.6	30.5 - 35.8

As seen in Table 1C.9, the total reserves for summer range from 20-30 percent and winter net reserves from 30-40 percent. Indications are that there may be difficulties in meeting future obligations, even if all future capacity additions are completed on schedule, which is questionable with nuclear plants. Total unavailable capability including scheduled maintenance averaged about 25 percent of planned capability for the 1977-1979 summer peak season. Assuming this for the future would make the CAPCO region deficit in actual reserves for the summer of 1982. Deficits could approach 1500 MW by 1987. However, summer peak demand forecasts do indicate a comparatively higher rate of growth than historical patterns. This would mitigate the problem if the estimates are on the high side. The CAPCO region which shows no capacity imports after 1980 in the ECAR 411 Report, will have to obtain capacity purchases from neighboring utilities.

Shown below are the projected growth rates of demand and capability for each period and the overall rates for 1981-1989.

Table 1C.10

Projected Energy and Demand Growth Rates
CAPCO REGION

	<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	<u>GWH</u>	<u>GROWTH %</u>	<u>(MW)</u>	<u>GROWTH %</u>	<u>(MW)</u>	<u>GROWTH %</u>	
1981	70,800		11,985		11,316		67.4
1982	73,410		12,444		11,695		67.3
1983	75,820		12,879		12,097		67.2
1984	78,320		13,348		12,484		66.8
1985	80,630		13,758		12,872		66.9
GROWTH 81-85		3.3		3.5		3.3	
1986	82,950		14,205		13,239		66.7
1987	85,350		14,613		13,633		66.7
1988	87,960		15,086		14,013		66.4
1989	90,470		15,479		14,386		66.7
GROWTH 86-89		2.9		2.9		2.8	
GROWTH 81-89		3.2		3.2		3.1	

The 1981-1985 summer demands are projected to grow at a compound rate of 3.5 percent; 1986-89, 2.9 percent; and overall 1981-89 rates of 3.2 percent. These rates, as discussed previously, are considerably higher than the summer 1977-79 period which experienced a 2.5 percent decline.

The winter demands are projected to grow at slightly slower rates; 3.3 percent for 1981-85, 2.8 percent for the 1986-1989 period, and 3.1 percent overall. This reflects an optimistic growth when compared to the 0.5 percent rate for the 1977-79 period.

Energy requirements are projected to grow 3.3 percent from 1981-85, 2.9 percent from 1986-89, and 3.2 percent for the overall period from 1981-89. Historically 1977-1979, the energy growth was 1 percent.

During the 1981-1985 period, only one major generating unit is expected to be placed in service. The nuclear unit, Perry #1, with net capability of 1205 MW, and an in-service date of May 1984. Shippingport, a 60 MW nuclear unit, is scheduled to be placed on inactive reserve in January 1982.

In the 1986-1989 period, two nuclear units are scheduled for installation; Beaver Valley #2 (833 MW) and Perry #2 (1205 MW), with in-service dates of May 1986 and May 1988 respectively.

There are no major installations or removals of capacity in 1983, 1985, 1987 or 1989.

The summer capability of units planned for the region in the period 1980-1989 is shown by fuel type in Table 1C.19. Major generating unit additions and retirements during the period are given in Table 1C.20. The fuel percentages for each type of capacity for the target years 1980, 1984, and 1989 are given below.

Table 1D.11

Planned Generating Capability by Type of Fuel (- %)
Summer Capability
CAPCO REGION

	Nuclear Steam	Coal Steam	Oil Steam	Oil CT	Oil IC	Hydro Conv.	Hydro PS	Total Capability
1980	12.1	75.8	4.6	5.0	0.2	0	2.3	100.0
1984	17.7	71.6	4.0	4.5	0.2	0	2.0	100.0
1989	26.6	63.8	3.6	4.0	0.2	0	1.8	100.0

Coal presently is the primary fuel for about 76 percent of the installed capacity of the region. Its percentage will decline to 64 percent by 1989 while nuclear capacity will rise from 12 percent to almost 27 percent by 1989. Oil-fired capacity will decline slightly from about 10 percent to 8 percent in the same period.

Pumped storage will decline from just over 2 percent of the total capability to slightly under 2 percent. The decline of the oil and hydro capability is the result of no new installations in these categories in an expanding generating base.

There is only one critical bulk power transmission facility that will not be in service when desired during the period 1981-1989, the double circuit 345 kV Harding Supply (also referred to as the Juniper-Harding Line). It was originally scheduled for service in December 1973 in order to provide the initial 345 kV supply to CEI's Harding Substation. The major portion (5.7 miles) of the line has been constructed and currently remains idle. Completion of the Harding Supply has been delayed by a series of court decisions and denial of a permit by the National Park Service since a portion of the planned line route would have traversed the Cuyahoga Valley National Recreation Area. Discussions continue with the National Park Service on determining a mutually satisfactory route.

In June 1977, as an expediency occasioned by the delay in the Harding Supply, the planned second step of the supply to the central area was constructed in advance and placed in service. This single line currently supplies three 345/138 kV substations serving the major load center in northeast Ohio. The continued inability to complete the Harding Supply restricts CEI's ability to import power under various contingency situations, posing a catastrophic threat to their central load area.

The projected in-service date for the Harding Supply is now April 1984. That date assumes the timely receipt of the necessary approvals to complete the line along a mutually satisfactory route.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure and the material which appears in the final ECAR report is normally limited to those items which are of particular significance to the overall region. The appraisal is based on a careful analysis of various studies carried out by the ECAR Transmission System Performance Working Group under the direction of the Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions were considered during the course of the various studies referred to above but no localized transmission problems were apparent in the CAPCO region.

The most recent ECAR appraisal studies were for Summer 1979 and Winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

Table 1D.12

Emergency Transfer Capability - MW
CAPCO REGION

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979-80 Capability</u>
ECAR to MAAC	3300+	3300+
ECAR to NPCC (NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC (VACAR)	1250	1900*
ECAR from MAAC	2450	3300+
ECAR from NPCC (NYPP)	3300+	2900
ECAR from MAIN	4000+	3800
ECAR from SERC (TVA)	2000	2100
ECAR from SERC (VACAR)	2700	2950*

* ETC Values determined with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No. 1. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No. 1 without suffering area-wide break-up and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to provide the facilities shown.

Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed as a result of excessive lag in the certification process or as a result of difficulties in financing these projects due to inadequate rate relief, then appropriate short term operating procedures will need to be developed in order to maintain, to the greatest extent possible, the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, are as follows:

Table 1D.13

Summer 1984 Emergency Transfer Capability - MW
CAPCO REGION

<u>Transfer</u>	<u>ETC MW</u>	<u>Transfer</u>	<u>ETC MW</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC	2900
ECAR to MAIN	2900	ECAR from MAIN	4000+
ECAR to SERC (TVA)	2500	ECAR from SERC (TVA)	3200
ECAR to SERC (VACAR)	2250	ECAR from SERC (VACAR)	5500+

The following table is a list of proposed bulk power lines to be constructed by CAPCO companies. It includes internal transmission facilities as well as interconnections with utilities in other regions. Many of these interconnections will become critical, since the CAPCO region's low reserve margins in the study period indicate a heavy dependence on capacity imports and therefore make the wheeling of large blocks of energy through the system necessary.

TABLE 1C.14
LIST OF PROPOSED BULK POWER LINES

CAPCO REGION

<u>LINE OWNERSHIP LIST</u>		<u>TERMINALS</u>	<u>LINE</u> <u>KM</u>	<u>LENGTH</u> <u>MI</u>	<u>PLANNED</u> <u>SERVICE</u> <u>DATE</u>	<u>NOMINAL</u> <u>VOLTAGE</u> <u>IN KV</u> <u>OPER DSGN</u>		<u>REMARKS</u>
<u>INTERCONNECTIONS</u>								
OE	CEI	Mansfield/Juniper	55.7	34.6	Jun 80	345	345	Increase Interchange Capability Relieve Overloads 1st CKT-D/C Towers Extend Mansfield-Hanna to Juniper By-passing Hanna Replaces Mansfield-Hanna
CEI	OE	Avon/Beaver	26.2	16.3	Dec 80	345	345	Increase Interchange Capability Relieve Overloads 2nd CKT-D/C Towers
OE	CEI	Mansfield/Harding	12.7	7.9	Apr 84	345	345	Increase Interchange Capability Relieve Overladds 1st CKT-D/C Towers Extend Mansfield-Juniper to Harding Ey-Passing Juniper Replace Mansfield-Juniper
DLCO	OE	Beaver Valley Mansfield-Hanna	0.9	0.6	Feb 86	345	345	Releive Overloads Deliver Generator Output D/C Loop Into Beaver Valley
OE	CEI	Hanna/Perry	81.3	50.5	Feb 88	345	345	Schedule is Under Study Could be advanced Deliver Generator Output Relieve Overloads 1st CKT-D/C Towers-8MI 2nd DKT D/C Tower

TABLE 1C.14

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LIST OF PROPOSED BULK POWER LINESCAPCO REGION

LINE OWNERSHIP LIST		TERMINALS	LINE LENGTH		PLANNED SERVICE DATE	NOMINAL VOLTAGE IN KV		REMARKS
			KM	MI		OPER	DSGN	
INTERCONNECTIONS								
CP	TECO DECO	Denawee/Allen JCT(TE)-DUDU	33.8	21.0	Jun 89	345	345	Provide Area Protection
CLEVELAND ELECTRIC ILLUMINATING CO.								
	CEI	Perry/Inland	70.3	43.7	Feb 83	345	345	Deliver Generator Output Relieve Overloads 1st CKT-D/C Towers
	CEI	Perry/Harding	70.3	43.7	Feb 83	345	345	Deliver Generator Output Relieve Overloads 2nd CKT-D/C Towers Restore Eastlake/Juniper Circuit
	CEI	Juniper/Harding	12.7	7.9	Apr 84	345	345	Relieve Overloads 2nd CKT-D/C Towers
DUQUESNE LIGHT COMPANY								
	DLCO	Crescent/Collier	29.9	18.6	Sep 80	345	345	Relieve Overloads Provide Area Reinforcement 1st CKT-D/C Tower to Beaver Valley-Collier Line 2nd CKT-D/C Towers into Collier
	DLCO	Carson/Bull Run	11.9	7.4	Jun 84	345	345	Provide Area Reinforcement 5.5 MI. Underground
	DLCO	Beaver Valley/Crescent	25.7	16.0	Feb 86	345	345	Deliver Generator Output Stability Considerations 2nd CKT-D/C Towers

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TABLE 1C.14
LIST OF PROPOSED BULK POWER LINES

CAPCO REGION

LINE OWNERSHIP LIST	TERMINALS	LINE LENGTH		PLANNED SERVICE DATE	NOMINAL VOLTAGE IN KV		REMARKS
		KM	MI		OPER	DSGN	
DUQUESNE LIGHT COMPANY							
DLCO	Collier/Bull Run	24.1	15.0	Apr 86	345	345	Provide Area Reinforcement Underground
DLCO	Brunot Island/Collier-Carson	0.1	0.1	Feb 87	345	345	Provide Area Reinforcement C/C Loop into Brunot Island
DLCO	Brunot Island/Crescent	20.9	13.0	Feb 89	345	345	Relieve 138 139 KV Heavy Loadings 1st CKT-D/C Tower Line
TOLEDO EDISON COMPANY							
TECO	Midway/Lemoyne-Allen Junction	0.0	0.0	Apr 85	345	345	Provide Area Reinforcement Relieve Overloads D/C Loop into Midway
OHIO EDISON SYSTEM (INCLUDES PENNSYLVANIA POWER CO.)							
OE	Carlisle/Star-Beaver	6.4	4.0	Mar 80	345	345	Relieve Overloads Provide Area Reinforcement D/C Loop to Carlisle
DE	Mansfield/Hanna	94.9	59.0	Jul 80	345	345	Deliver Generator Output Relieve Overloads 2nd CKT-D/C Towers
DE	Hoytdale/Mansfield-Highland	45.0	28.0	Jun 85	345	345	Relieve Overloads Increase Interchange Capability D/C Loop to Hoytdale

Table 1C.15

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
CAPCO REGION

	<u>1977</u> <u>Summer</u>	<u>1977/78</u> <u>Winter</u>	<u>1978</u> <u>Summer</u>	<u>1978/79</u> <u>Winter</u>	<u>1979</u> <u>Summer</u>	<u>1979/80</u> <u>Winter</u>
1. Planned Capability	13,648	15,000	15,164	15,547	15,391	15,423
2. Peak Demand	11,384	10,347	11,194	10,641	10,809	10,442
3. Planned Reserves (1-2)	2,262	4,653	3,970	4,706	4,582	4,981
4. Planned Reserves (%) (3-2) x 100%	19.0	45	35.5	43.4	42.4	47.7
5. Net Transactions (Imports - Export)	26	-456	-46	68	165	11
6. Total Capability (1+5)	13,672	14,544	15,118	15,615	15,556	15,434
7. Total Reserves (6-2)	2,288	4,197	3,924	4,774	4,747	4,992
8. Total Reserves (%) (7-2) x 100%	20.1	40.6	35.1	44.0	43.9	47.8
9. Scheduled Maintenance	414	656	1,005	1,073	830	2,353
10. Capability After Maintenance (6-9)	13,258	13,888	14,113	14,540	14,726	13,081
11. Reserves After Maintenance (10-2)	1,874	3,541	2,910	3,699	3,917	2,639
12. Reserves After Maintenance (%) (11-2) x 100%	16.5	34.2	26.1	34.1	36.2	25.3
13. Inoperable Capability*	0	0	0	0	0	0
14. Available Capability (10-13)	13,258	13,888	14,113	14,540	14,726	13,081
15. Available Reserves (14-2)	1,874	3,541	2,910	3,699	3,917	2,639
16. Available Reserves (%) (15-2) x 100%	16.5	34.2	26.1	34.1	36.2	25.3
17. Forced Outages	2,002	5,118	3,742	5,622	3,808	2,227
18. Actual Capability After Forced Outages (14-17)	11,256	8,770	10,371	8,918	10,918	10,854
19. Actual Reserves (18-2)	-128	-1,577	-823	-1,923	109	412
20. Actual Reserves (%) (19-2) x 100%	-1.1	-15.2	-7.4	-17.7	1.0	3.9

*Included in Item 17

Table 1C.16

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
CAPCO REGION

	1980	
	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	14,611	15,764
2. Peak Demand	11,434	10,904
3. Planned Reserves (1-2)	3,177	4,860
4. Planned Reserves (%) (3-2) x 100%	27.8	44.6
5. Net Transactions (Imports - Exports)	278	170
6. Total Capability (1-5)	14,889	15,934
7. Total Reserves (6-2)	3,455	5,030
8. Total Reserves (%) (7-2) x 100%	30.2	46.1
9. Scheduled Maintenance <u>1/</u>	731	788
10. Capability After Maintenance (6-9)	14,158	15,146
11. Reserves After Maintenance (10-2)	2,724	4,242
12. Reserves After Maintenance (%) (11-2) x 100%	23.8	38.9
13. Inoperable Capability	135	135
14. Available Capability (10-13)	14,023	15,011
15. Available Reserves (14-2)	2,589	4,107
16. Available Reserves (%) (15-2) x 100%	22.6	37.7
17. Forced Outages*	0	0
18. Actual Capability After Forced Outages (14-17)	14,023	15,011
19. Actual Reserves (18-2)	2,589	4,107
20. Actual Reserves (%) (19-2) x 100%	22.6	37.7

1/ 5% of Total Planned Capability Assumed by ERA-From ECAR ERA 411 Report

* No data available.

Table 1C.17

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
CAPCO REGION

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	15445	15747	15427	15750	15431	15753	16610	16958	16610	16958
2. Peak Demand	11985	11316	12444	11695	12879	12097	13348	12484	13758	12872
3. Planned Reserves (1-2)	3460	4431	2983	4055	2552	3656	3262	4474	2852	4086
4. Planned Reserves (%) (3-2) x 100%	28.9	39.2	24.0	34.7	19.8	30.2	24.4	35.8	20.7	31.7
5. Net Transactions (Imports-Exports)	164	0	0	0	0	0	0	0	0	0
6. Total Capability (1+5)	15609	15747	15427	15750	15431	15753	16610	16958	16610	16958
7. Total Reserves (6-2)	3624	4431	2983	4055	2552	3656	3262	4474	2852	4086
8. Total Reserves (%) (7-2) x 100%	30.2	39.2	24.0	34.7	19.8	30.2	24.4	35.8	20.7	31.7
9. Scheduled Maintenance*	0	0	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	15609	15747	15427	15750	15431	15753	16610	16958	16610	16958
11. Reserves After Maintenance (10-2)	3624	4431	2983	4055	2552	3656	3262	4474	2852	4086
12. Reserves After Maintenance (%) (11-2) x 100%	30.2	39.2	24.0	34.7	19.8	30.2	24.4	35.8	20.7	31.7
13. Inoperable Capability	135	135	135	135	135	135	135	135	135	135
14. Available Capability (10-13)	15474	15612	15292	15615	15296	15618	16475	16823	16475	16823
15. Available Reserves (14-2)	3489	4296	2848	3920	2417	3521	3127	4339	2717	3951
16. Available Reserves (%) (15-2) x 100%	29.1	38.0	22.9	33.5	18.8	29.1	23.4	34.8	19.7	30.7
17. Forced Outages*	0	0	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	15474	15612	15292	15615	15296	15618	16475	16823	16475	16823
19. Actual Reserves (18-2)	3489	4296	2848	3920	2417	3521	3127	4339	2717	3951
20. Actual Reserves (%) (19-2) x 100%	29.1	38.0	22.9	33.5	18.2	29.1	23.4	34.8	19.7	30.7

* No data provided.

Table 1C.18

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
CAPCO REGION

	<u>1986</u>		<u>1987</u>		<u>1988</u>		<u>1989</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	17430	17791	17430	17791	18639	19025	18639	19025
2. Peak Demand	14205	13239	14613	13633	15086	14013	15479	14386
3. Planned Reserves (1-2)	3225	4552	2817	4158	3553	5012	3160	4639
4. Planned Reserves (%) (3-2) x 100%	22.7	34.4	19.3	30.5	23.6	35.8	20.4	32.2
5. Net Transactions (Imports-Exports)	0	0	0	0	0	0	0	0
6. Total Capability (1+5)	17430	17791	17430	17791	18639	19025	18639	19025
7. Total Reserves (6-2)	3225	4552	2817	4158	3553	5012	3160	4639
8. Total Reserves (%) (7-2) x 100%	22.7	34.4	19.3	30.5	23.6	35.8	20.4	32.2
9. Scheduled Maintenance *	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	17430	17791	17430	17791	18639	19025	18639	19025
11. Reserves After Maintenance (10-2)	3225	4552	2817	4158	3553	5012	3160	4639
12. Reserves After Maintenance (%) (11-2) x 100%	22.7	34.4	19.3	30.5	23.6	35.8	20.4	32.2
13. Inoperable Capability	135	135	135	135	135	135	135	135
14. Available Capability (10-13)	17295	17656	17295	17656	18504	18890	18504	18890
15. Available Reserves (14-2)	3090	4417	2682	4023	3418	4877	3025	4504
16. Available Reserves (%) (15-2) x 100%	21.8	33.4	18.4	29.5	22.7	34.8	19.5	31.3
17. Forced Outages*	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	17295	17656	17295	17656	18504	18890	18504	18890
19. Actual Reserves (18-2)	3090	4417	2682	4023	3418	4877	3025	4504
20. Actual Reserves (%) (19-2) x 100%	21.8	33.4	18.4	29.5	22.7	34.8	19.5	31.3

*No data provided.

Table 1C.19

INSTALLED NET CAPABILITY BY TYPE OF FUEL - MW
CAPCO REGION

SUMMER CAPABILITY

YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	OIL		PUMPED STORAGE	TOTAL CAPABILITY
				COMBUST. TURBINE	INTERNAL COMBUST.		
1980	1,776	11,076	672	727	30	330	14,611
% TOTAL	12.1	75.8	4.6	5.0	0.2	2.3	100.0
1981	1,786	11,894	672	733	30	330	15,445
% TOTAL	11.6	77.0	4.4	4.7	0.2	2.1	100.0
1982	1,754	11,904	672	737	30	330	15,427
% TOTAL	11.4	77.2	4.4	4.7	0.2	2.1	100.0
1983	1,754	11,904	672	741	30	330	15,431
% TOTAL	11.4	77.1	4.4	4.8	0.2	2.1	100.0
1984	2,933	11,904	672	741	30	330	16,610
% TOTAL	17.7	71.6	4.0	4.5	0.2	2.0	100.0
1985	2,933	11,904	672	741	30	330	16,610
% TOTAL	17.7	71.6	4.0	4.5	0.2	2.0	100.0
1986	3,753	11,904	672	741	30	330	17,430
% TOTAL	21.5	68.2	3.8	4.3	0.2	2.0	100.0
1987	3,753	11,904	672	741	30	330	17,430
% TOTAL	21.5	68.2	3.8	4.3	0.2	2.0	100.0
1988	4,962	11,904	672	741	30	330	18,639
% TOTAL	26.6	63.8	3.6	4.0	0.2	1.8	100.0
1989	4,962	11,904	672	741	30	330	18,639
% TOTAL	26.6	63.8	3.6	4.0	0.2	1.8	100.0

TABLE 1C.20

MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS AND (REMOVALS)

CAPCO REGION

<u>SYSTEM</u>	<u>STATION</u>	<u>UNIT TYPE</u>	<u>FUEL TYPE</u>	<u>NET CAPABILITY</u>	<u>IN-SERVICE DATE APRIL 79 "383" REPORT</u>	<u>IN-SERVICE DATE APRIL 80 "411" REPORT</u>
CAPCO	Mansfield #3	ST	Coal	780	10/80	10/80
	Shippingport	NU	Thorium	-62	-	1/82
	Perry #1	NU	Uranium	1,205	5/83	5/84
	Beaver Valley #2	NU	Uranium	833	5/84	5/86
	Perry #2	NU	Uranium	1,205	5/85	5/88

No. Installation and Removals: 83, 85, 87, 89

Cincinnati, Columbus, Dayton Group - CCD

ELECTRIC REGION 14

Historical Perspective

Electric Region 14 includes the Cincinnati, Columbus, Dayton Group (CCD) and the municipal system of Hamilton, Ohio.

The CCD group is comprised of three separate companies: Cincinnati Gas and Electric Company, Columbus and Southern Ohio Electric Company, and the Dayton Power and Light Company. There are no formal requirements for participation in the group. The companies comprising the CCD group have agreed to coordinate their generation and transmission programs and to build certain generation and bulk transmission facilities as tenants in common. The three companies currently share generating units in four plants and 15 to 20 transmission lines with varying percentages of ownership. In addition to co-ownership of facilities, the members participate in coordination of load projections spinning reserves, exchange capacity and energy, scheduled maintenance programs, and economic dispatch of generating units.

The municipal system of the city of Hamilton, Ohio also located in the CCD Group is interconnected with Cincinnati Gas and Electric Company. The system has generating capability and purchases energy when required.

In 1978, utilities in the CCD region served 1,347,000 customers in Ohio, of which 1,207,000 were residential, 121,000 commercial, 8,000 were industrial, and 9,000 others.

The CCD companies, located in the Central portion of the ECAR Reliability Council are highly interconnected internally and with neighboring ECAR utilities by 345 KV and 138 KV. It's geographical position in the ECAR region does not lend itself to interconnections with neighboring Councils.

The CCD region has historically been a summer peaking region. Shown below are the region's summer and winter peaks for the period 1977-79.

Table 1D.1

Historical Peak Demands* - MW
CCD REGION

	<u>SUMMER</u>			<u>WINTER</u>		
	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	5776	<u>6737</u>	6226	6118	<u>6312</u>	5587
1978	6602	<u>6643</u>	6493	5533	<u>6403</u>	6232
1979	6048	<u>6431</u>	<u>6769</u>	5839	<u>5971</u>	<u>5986</u>

Underline indicates seasonal peak.

* Non-coincident

The summer peak demands are usually dependent on climate conditions and are temperature/humidity sensitive. In the last three years peaks have been in July and August.

The winter peak usually occurs in January or February. A shift in the winter peak from these months is generally the result of a weather bias. There is occasionally some sensitivity to unusual economic conditions in the region as well.

The winter peak during the 1977-79 period was 4-12% lower than the corresponding yearly summer peaks, a normal situation.

The following table shows the amount of generating capacity down for scheduled maintenance performed each period and also the capability unavailable because of forced unit and partial unit outages.

Table 1D.2

Scheduled Maintenance And Unavailable Capabilities -(MW)
CCD REGION

	<u>SUMMER</u>			<u>WINTER</u>		
	<u>SCHEDULED</u>	<u>OTHER</u>	<u>TOTAL</u>	<u>SCHEDULED</u>	<u>OTHER</u>	<u>TOTAL</u>
	<u>MAINTENANCE</u>	<u>UNAVAILABLE</u>	<u>UNAVAILABLE</u>	<u>MAINTENANCE</u>	<u>UNAVAILABLE</u>	<u>UNAVAILABLE</u>
1977	613	639	1,252	2,224	2,050	4,274
1978	1,266	1,210	2,476	910	1,750	2,660
1979	998	1,244	2,242	1,230	764	1,994

The percentage of planned capability that was unavailable for reasons other than scheduled maintenance varied from 8-14% in the summer and from 8-24% in the winter.

The reserve margins for the 1977-79 period are indicated below. The table shows the effects of scheduled maintenance and other outages.

Table 1D.3

Historical Seasonal Reserves
CCD REGION

SUMMER

	<u>Peak Demand</u>	<u>Total Capability</u>	<u>Total Reserves</u>	<u>Capability After Main-tenance</u>	<u>Available Reserves</u>	<u>Actual Capability</u>	<u>Actual Reserves</u>
	(MW)	(MW)	(%)	(MW)	(%)	(MW)	(%)
1977	6,737	8,411	24.8	7,798	15.7	7,159	6.3
1978	6,647	9,279	39.6	8,013	20.6	6,803	2.3
1979	6,769	8,909	31.6	7,911	16.9	6,667	(1.5)

WINTER

1977	6,312	8,718	38.1	6,494	2.9	4,444	(29.6)
1978	6,403	9,422	47.1	8,512	32.9	6,762	5.6
1979	5,991	9,164	53.0	7,934	32.4	7,170	19.7

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Summer actual reserves were barely adequate when considering the effects of scheduled and forced outages. Winter actual reserves were adequate except for the winter 1977/78. This was due primarily to the coal strike, and a combination of high scheduled maintenance to take advantage of low plant output due to fuel constraint and forced outages.

Show below are the CCD regions energy requirements, summer and winter demands and annual load factors for the 1977-79 period.

Table 1D.4Historical Energy, Peaks* and Load Factors
CCD REGION

	<u>Energy Requirement</u>		<u>Summer Demand</u>		<u>Winter Demand</u>		<u>Annual Load Factor</u>
	(GWH)	(Growth-%)	(MW)	(Growth-%)	(MW)	(Growth-%)	(%)
1977	34,059	-	6,737	-	6,312	-	57.7
1978	34,510	1.3	6,647	(1.3)	6,403	1.4	59.3
1979	35,677	3.4	6,769	1.8	5,991	(6.4)	60.2
Growth 77-79		2.4		0.2		(2.5)	

* Non-coincident

Energy requirements over the period 1977-79 have grown at a compound rate of 2.4%. This is slightly higher than the average for the ECAR region.

Summer peak demand growth rates for 1977-79 are less than tradition patterns. This is due in part to cool summers, but mainly to conservation techniques and increased cost of energy.

Winter peak demands have shown a 2.5% decline from 1977 to 1979. This was the result of a 400 MW decrease in the 1979 winter peak. Similar winter declines in 1979 are evident in other ECAR systems which could indicate a weather related situation.

Load factors were lower than other ECAR systems which is indicative of utilities that serve large urban loads.

Current Perspective

The projected 1980 summer and winter non-coincident peak demand requirements are shown below:

Table 1D.5Projected 1980 Seasonal Peak Demand* - MW
CCD REGION

<u>Summer</u>			<u>Winter</u>		
June	July	Aug.	Dec.	Jan.	Feb.
6,706	<u>7,324</u>	6,958	6,635	<u>6,904</u>	6,411

* Non-coincident

The extremely high rate of growth between the actual 1979 and the projected 1980 peak demands was probably the result of over estimation of the 1979 peaks (summer and winter) If, indeed, the 1980 forecast is inflated due to forecast error, reserve margins could benefit throughout the 1980/89 period.

The 1980 summer planned capability of the CCD region is estimated to be 8,948 MW and the summer non-coincident peak demand requirements are projected to be 7,324 MW excluding 12 MW of Columbus & Southern Ohio interruptible demand. After adjustments for scheduled receipts and deliveries, total reserves are 1,868 or 25.5%.

In the ECAR ERA-411 report for the future (1980-1989) the CCD region does not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an indication of scheduled maintenance for the entire region.

The estimate prepared for the "411" report is based on the level of scheduled maintenance that is currently projected for the periods of heaviest load during the upcoming summer and winter seasons, i.e., five percent of total planned capability during the summer of 1980 and five percent of total planned capability during the winter of 1980/81.

The summer and winter 1980 reserve margins for the CCD electric region are shown below:

Table 1D.6

1980 Reserve Margins*
CCD REGION

Summer						Winter					
Planned Reserves		Total Reserves		Available Reserves**		Planned Reserves		Total Reserves		Available Reserves**	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
1,624	22.2	1,868	25.5	1,416	19.3	2,991	43.3	3,246	47.0	2,746	39.8

* Based on ERA Form 411

** 5% of Total Installed Capability Assumed - From ECAR ERA Form 411 Report of Scheduled Outages.

The margins shown above have not been adjusted for forced outages of generation equipment since the amount of these outages are generally unknown ahead of time, but have run as high as 24% in 1977. If these outages for 1980 do not exceed the maximum outages of the 1977-79 period, 14% of planned capability during the summer and 24% during the winter, the resultant actual reserve would be 163 MW or 2.2% for the summer and 371 MW or 5.4% for the winter.

The summer 1980 capability of the generating facilities planned in the CCD region will be 8,948 MW. The capability breakdown by fuel type is shown below:

Table 1D.7
1980 Summer Planned Capability in MW
CCD REGION

	<u>Nuclear</u> <u>Steam</u>	<u>Coal</u> <u>Steam</u>	<u>Oil</u>			<u>Gas</u>		<u>Hydro</u> <u>Conv</u>	<u>Pumped</u> <u>Storage</u>	<u>Total</u> <u>Capability</u>
			<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>CT</u>	<u>IC</u>			
	-	7,719	260	566	89	221	92	1	-	8,948
% of Total	-	86.3	2.9	6.3	1.0	2.5	1.0	0.0	-	100.0

Of the current capability, 86% is coal-fired steam capacity, 10% is oil-fired steam, combustion turbine and internal combustion capacity, and 4% is gas-fired combustion turbine and internal combustion capacity. There is only 1 MW of hydroelectric capacity. No new capacity is scheduled to be installed in the CCD region in 1980.

The projected 1980 energy requirements, summer and winter demand requirements and annual load factor for the region are shown below:

Table 1D.8
1980 Load Requirements
CCD REGION

<u>Energy Requirement</u> (GWH)	<u>Summer Peak Demand*</u> (MW)	<u>Winter Peak Demand*</u> (MW)	<u>Annual L.F</u> (%)
37,410	7,324	6,904	58.2
% of Growth 4.9 1980/79	8.2	15.2	-

* Non-coincident

The high rates of growth have been discussed previously.

Delays in future critical bulk power transmission facilities that will not be in service when needed are reported under Item 5-C of the ERA-411 report. There are no lines in this category in the CCD region.

Future Pperspective

The range of total reserves for the CCD region for the periods 1981-85 and 1986-1989 are tabulated below:

Table 1D.9

Range of Total Reserves-%
CCD REGION

<u>1981 - 1985</u>		<u>1986 - 1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
23.7-35.9	39.3-48.9	22.8-31.4	36.3-45.9

As seen above the total reserves span a large range from 23.7% in the summer of 1985 to 48.9% in the winter of 1982/83. Indications are that the CCD region will have no serious difficulties in meeting obligations, if there are no unusual delays in completing scheduled capacity additions. Total unavailable capacity including scheduled maintenance in 1977-79 varied from 15% to 27% of installed capability for the summer peak season, and from 22 to 50% for the winter.

If a total average non-availability rate of 22% is assumed for the summer in the 1981-89 period, only in 1985 and 1989 would actual reserves be deficient at 226 MW (- 2.5%) and 434 MW (- 4.2%) respectively. Assuming a total outage rate of 30% for the winter peaks, after 1986/87 actual reserves would be deficient in the winter of 1987/88, 1988/1989, and 1989/90. The maximum deficiency would be 522 MW or (-5.5%) in 1988/89. As discussed previously, since peak estimates in the early portion of the forecast period appear high, these deficiencies both summer and winter, may not materialize.

Shown below are the projected growth rates of energy and demand for each period and the overall rates for 1981 - 1989.

Table 1D.10

Projected Energy and Demand Growth Rates
CCD REGION

<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	<u>GROWTH</u>		<u>GROWTH</u>		<u>GROWTH</u>	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(%)
1981	39230	7695		7258		58.2
1982	40640	7961		7539		58.3
1983	42460	8301		7887		58.5
1984	44280	8647		8229		58.6
1985	46200	8976		8553		58.6
GROWTH 81-85	4.2		3.9		4.2	
1986	48020	9284		8866		59.0
1987	49740	9599		9195		59.2
1988	51660	9940		9549		59.3
1989	53780	10294		9919		59.6
GROWTH 86-89	3.8		3.5		3.8	
GROWTH 81-89	4.0		3.7		4.0	

The 1981-1985 summer demands are projected to grow at a compound rate of 3.9%, 1986-1989 growth is forecasted at 3.5% with an overall growth in 1981-1989, of 3.7%. These rates are considerably higher than the summer 1977-79 growth of less than 1%.

The winter demand growth rates are projected to grow at a compound rate of 4.2% for the 1981-85 period, 3.8% for the 1986-89 period, with an overall average 1981-89 rate of 4.0% as compared to the 1977-79 reduction of 2.5%.

The summer peak is expected to decline from about 6% higher than the corresponding winter peak to about 3% higher than the winter peak within the forecast period.

Energy requirements are projected to grow 4.2% from 1981-85, 3.8% from 1986-89 and 4.0% for the overall period from 1981-89. Historically, 1977-79, the energy growth was 2.4%. The forecast indicates continued optimistic economic activity in the region.

During the 1981-85 period, six generating units are expected to be placed in service.

Four of these are base-load coal-fired steam units, and each is rated at 600 MW. The units, East Bend #2, Killen #2, East Bend #1, and Killen #1, will be installed in January 1981, October 1982, October 1985 and December 1985 respectively. Zimmer #1, a nuclear unit rated at 807 MW has an in-service date of January 1981. A 237 MW oil-fired combustion turbine, Hayden, is also scheduled for installation in January 1984.

In the 1985-89 period, three units are scheduled: 2 coal-fired steam units and an oil-fired combustion turbine. The coal units, Poston #5, and East Bend #3 are rated at 375 MW and 600 MW respectively and have in-service dates of January 1987 and October 1989. The 79 MW Walnut combustion turbine, is scheduled for installation in January 1988.

There are no installations or retirements in 1980, 1983, or 1986.

The summer capability of units planned in the region for the period 1980-1989 is shown by fuel type in Table 1D.19. Major generating unit additions and retirements during the period are given in Table 1D.20. The percentages of each type of capacity for the target years 1980, 1984, 1989 are given below.

Table 1D.11

Planned Generating Capacity by Type of Fuel (- %)
CCD REGION

Summer Capability

<u>Year</u>	<u>Nuclear Steam</u>	<u>Coal Steam</u>	<u>Oil</u>			<u>Gas</u>		<u>Hydro Conv.</u>	<u>Pumped Storage</u>	<u>Total Capability</u>
			<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>CT</u>	<u>IC</u>			
1980	-	86.3	2.9	6.3	1.0	2.5	1.0	0.0	-	100.0
1984	7.1	80.1	2.3	6.9	0.8	2.0	0.8	0.0	-	100.0
1989	6.3	82.8	1.3	6.5	0.7	1.7	0.7	0.0	-	100.0

Coal presently is the primary fuel for about 86% of the installed capacity of the region. Only a slight change to about 83% is forecasted for 1989. The slight decline is due to the addition of the first nuclear unit in the region in 1981. This will bring the percentage of nuclear up to 6.3% in 1989. Oil-fired capacity is expected to decline from about 10% to about 9% and gas-fired from 3.5% to 2.5% in the 1981 period. There is no pumped storage and only 1 MW of conventional hydroelectric in the region.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure and the material which appears in the final draft represents facilities of particular significance to the overall region. The appraisal is based on a careful analysis of various studies carried out by the ECAR Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions were considered during the course of the various studies referred to above and the following operating procedures were developed: (only CCD described below).

CSOE--Hyatt-Delaware 138 kV Circuit

The 138 kV Hyatt-Delaware transmission line is loaded slightly above its emergency rating of 287 MVA in the 1979-80 winter base case. In order to relieve this condition, it may become necessary to open Delaware-Tangy interconnection if problems develop during periods of heavy interregional or transregional power transfers.

The most recent ECAR appraisal studies were for Summer 1979 and Winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

Table 1D.12

Emergency Transfer Capability-MW CCD REGION

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979-80 Capability</u>
ECAR to MAAC	3300*	3300*
ECAR to NPCC(NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC(TVA)	1800	1600
ECAR to SERC(VACAR)	1250	1900*

*ETC Values determined with established operating procedures in effect.

XI.1.80

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979/80 Capability</u>
ECAR from MAAC	2450	3300
ECAR from NPCC(NYPP)	3300*	2900
ECAR from MAIN	4000*	3800
ECAR from SERC(TVA)	2000	2100
ECAR from SERV(VACAR)	2700	2950*

*ETC Values determine with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No.1. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No. 1 without suffering area-wide break-up and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to provide the facilities shown. Should any of the EHV transmission facilities planned for the 1980-84 period be delayed as a result of excessive lag in the certification process or as a result of difficulties in financing these projects due to inadequate rate relief, then appropriate short term operating procedures will need to be developed in order to maintain, to the greatest extent possible, the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

Table 1D.13

Summer 1984 Emergency Transfer Capability - MW
CCD REGION

<u>Transfer</u>	<u>ETC MW</u>	<u>Transfer</u>	<u>ETC MW</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC(NYPP)	1950	ECAR from NPCC	2900
ECAR to MAIN	2900	ECAR from MAIN	4000*
ECAR to SERC(TVA)	2500	ECAR from SERC(TVA)	3200
ECAR to SERC(VACAR)	2250	ECAR from SERC(VACAR)	5500*

TABLE 1.D.14

List of Proposed Bulk Power Lines
CCD Group

LINE OWNERSHIP LIST	TERMINALS	LINE LENGTH		PLANNED SERVICE DATE	NOMINAL VOLTAGE IN KV		REMARKS
		KM	MI		OPER	DSGN	
<u>INTERCONNECTIONS</u>							
CG&E DP&L	Miami Fort / Miami	127.6	79.3	Feb 80	345	345	Deliver Generator Output
<u>THE DAYTON POWER AND LIGHT COMPANY</u>							
DP&L	Bath / Greene-Miami	0.0	0.0	May 82	345	345	Increase Interchange Capability
DP&L	Killen / Stuart-Marquis (Marquis)	10.4	6.5	Jul 82	345	345	Deliver Generator Output
DP&L	Madison / Miami Fort-Miami (DPL)	0.0	0.0	May 85	345	345	Increase Interchange Capability
DP&L	Killen Station / Bath	142.3	88.4	May 86	345	345	Deliver Generator Output Relieve Overloads
DP&L	Richland / Killen-Bath	0.0	0.0	May 86	345	345	Provide Area Protection
DP&L	West Milton / Madison-Miami	0.0	0.0	May 89	345	345	Increase Interchange Capability
DP&L	Killen / Stuart-Marquis (Stuart)	8.8	5.5	Jan 81	345	345	Provide Initial Station Power and Deliver Generator Output
<u>THE CINCINNATI GAS & ELECTRIC COMPANY</u>							
CG&E	East Bend / Miami Fort	24.6	15.3	Sep 85	345	345	Deliver Generator Output
CG&E	West End / Terminal	17.3	10.8	Sep 89	345	345	Deliver Generator Output
CG&E	East Bend / Silver Grove	57.3	35.6	Sep 89	345	345	Deliver Generator Output
CG&E	Zimmer / Port Union	74.0	46.0	Jan 80	345	345	Deliver Generator Output
CG&E	East Bend / Terminal	22.5	14.0	Apr 80	345	345	Deliver Generator Output
CG&E	East Bend / Tanners	22.5	14.0	Apr 80	345	345	Deliver Generator Output
CG&E	Todhunter / Miami Fort	66.8	41.5	Jun 80	345	345	Deliver Generator Output
CG&E	Red Bank / Silver Grove-Terminal	0.0	0.0	Oct 80	345	345	Relieve Area Overloads
CG&E	East Bend / West-End	50.7	31.5	May 84	345	345	Deliver Generator Output
<u>COLUMBUS & SOUTHERN OHIO ELECTRIC CO.</u>							
CSOE	Walnut / Bixby	0.6	0.4	Oct 83	345	345	Deliver Generator Output (Nct required if alternate generator site is used.)
CSOE	Chillicothe / Marquis-Bixby	0.0	0.0	Oct 84	345	345	Local Area Support
CSOE	Poston / Kirk-Bixby	88.5	55.0	Oct 86	345	345	Deliver Generator Output

TABLE 1.D.15

Historical Capability (MW) and Reserves (MW and Percent)
CCD REGION

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	8290.0	8602.0	9165.0	9312.0	8999.0	9258.0
2. Peak Demand	6737.0	6312.0	6647.0	6403.0	6769.0	5991.0
3. Planned Reserves (1 - 2)	1553.0	2290.0	2518.0	2909.0	2230.0	3267.0
4. Planned Reserves (%) (3 - 2) x 100%	23.1	36.3	37.9	45.4	32.9	54.5
5. Net Transactions (Imports - Exports)	121.0	116.0	114.0	110.0	-90.0	-94.0
6. Total Capability (1 + 5)	8411.0	8718.0	9279.0	9422.0	8909.0	9164.0
7. Total Reserves (6 - 2)	1674.0	2406.0	2632.0	3019.0	2140.0	3173.0
8. Total Reserves (%) (7 - 2) x 100%	24.8	38.1	39.6	47.1	31.6	53.0
9. Scheduled Maintenance	613.0	2224.0	1266.0	910.0	998.0	1230.0
10. Capability After Maintenance (5 - 9)	7798.0	6494.0	8013.0	8512.0	7911.0	7934.0
11. Reserves After Maintenance (10 - 2)	1061.0	182.0	1366.0	2109.0	1142.0	1943.0
12. Reserves After Maintenance (%) (11 - 2) x 100%	15.7	2.9	20.6	32.9	16.9	32.4
13. Inoperable Capability *	0.0	0.0	0.0	0.0	0.0	0.0
14. Available Capability (10 - 13)	7798.0	6494.0	8013.0	8512.0	7911.0	7934.0
15. Available Reserves (14 - 2)	1061.0	182.0	1366.0	2109.0	1142.0	1943.0
16. Available Reserves (%) (15 - 2) x 100%	15.7	2.9	20.6	32.9	16.9	32.4
17. Forced Outages	639.0	2050.0	1210.0	1750.0	1244.0	764.0
18. Actual Capability After Forced Outages (14 - 17)	7159.0	4444.0	6803.0	6762.0	6667.0	7170.0
19. Actual Reserves (18 - 2)	422.0	-1868.0	156.0	359.0	-102.0	1179.0
20. Actual Reserves (%) (19 - 2) x 100%	6.3	-29.6	2.3	5.6	-1.5	19.7

* Included in Item 17

TABLE 1.D.16

Current Capability (MW) and Reserves (MW and Percent)
CCD REGION

	1980	
	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	8948.0	9895.0
2. Peak Demand	7324.0	6904.0
3. Planned Reserves (1 - 2)	1624.0	2991.0
4. Planned Reserves (%) (3 - 2) x 100%	22.2	43.3
5. Net Transactions (Imports - Exports)	244.0	255.0
6. Total Capability (1 + 5)	9192.0	10150.0
7. Total Reserves (6 - 2)	1868.0	3246.0
8. Total Reserves (%) (7 - 2) x 100%	25.5	47.0
9. Scheduled Maintenance <u>1/</u>	447.0	495.0
10. Capability After Maintenance (6 - 9)	8745.0	9655.0
11. Reserves After Maintenance (10 - 1)	1421.0	2751.0
12. Reserves After Maintenance (%) (11 - 2) x 100%	19.4	39.8
13. Inoperable Capability	5.0	5.0
14. Available Capability (10 - 13)	8740.0	9650.0
15. Available Reserves (14 - 2)	1416.0	2746.0
16. Available Reserves (%) (15 - 2) x 100%	19.3	39.8
17. Forced Outages <u>2/</u>	0.0	0.0
18. Actual Capability After Forced Outages (14 - 17)	8740.0	9650.0
19. Actual Reserves (18 - 2)	1416.0	2746.0
20. Actual Reserves (%) (19 - 2) x 100%	19.3	39.8

1/ Five percent of total planned capability assumed by ERA from ECAR 411 Report.

2/ No information supplied.

TABLE 1.D.17

Future Capability (MW) and Reserves (MW and Percent)
CCD REGION

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	10313	10632	10313	11232	10913	11469	11108	11469	11108	12669
2. Peak Demand	7595	7258	7961	7539	8301	7887	8647	8229	8976	8553
3. Planned Reserves (1-2)	2518	3374	2352	3693	2612	3582	2461	3240	2132	4116
4. Planned Reserves (%) (3-2) x 100%	34.0	46.5	29.5	49.0	31.5	45.4	28.5	39.4	23.8	48.1
5. Net Transactions (Imports - Exports)	141	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0
6. Total Capability (1+5)	10454	10628	10309	11228	10909	11465	11104	11465	11104	12665
7. Total Reserves (6-2)	2759	3370	2348	3689	2608	3578	2457	3236	2128	4112
8. Total Reserves (%) (7-2) x 100%	35.9	46.4	29.5	48.9	31.4	45.4	28.4	39.3	23.7	48.1
9. Scheduled Maintenance *	0	0	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	10454	10628	10309	11228	10909	11465	11104	11465	11104	12665
11. Reserves After Maintenance (10-2)	2759	3370	2348	3689	2608	3578	2457	3236	2128	4112
12. Reserves After Maintenance (%) (11-2) x 100%	35.9	46.4	29.5	48.9	31.4	45.4	28.4	39.3	23.7	48.1
13. Inoperable Capability	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
14. Available Capability (10-13)	10449	10623	10304	11223	10904	11460	11099	11460	11099	12660
15. Available Reserves (14-2)	2754	3365	2343	3684	2603	3573	2452	3231	2123	4107
16. Available Reserves (%) (15-2) x 100%	35.8	46.4	29.4	48.9	31.4	45.3	28.4	39.3	23.7	48.0
17. Forced Outages *	0	0	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages	10449	10623	10304	11223	10904	11460	11099	11460	11099	12660
19. Actual Reserves (18-2)	2754	3365	2343	3684	2603	3573	2452	3231	2123	4107
20. Actual Reserves (%) (19-2) x 100%	35.8	46.4	29.4	48.9	31.4	45.3	28.4	39.3	23.7	48.0

* No Information supplied.

TABLE 1.D.18

Future Capability (MW) and Reserves (MW and Percent)
CCD REGION

	1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	12206	12942	12581	13021	12646	13021	12646	13996
2. Peak Demand	9284	8866	9599	9295	9940	9549	10294	9917
3. Planned Reserves (1-2)	2922	4076	2982	3826	2706	3472	2352	4079
4. Planned Reserves (%) (3-2) x 100%	31.5	46.0	31.1	41.6	27.2	36.4	22.8	41.1
5. Net Transactions (Imports-Exports)	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0
6. Total Capability (1+5)	12202	12938	12577	13017	12642	13017	12642	13992
7. Total Reserves (6-2)	2918	4072	2978	3822	2702	3468	2348	4075
8. Total Reserves (%) (7-2) x 100%	31.4	45.9	31.0	41.6	27.2	36.3	22.8	41.1
9. Scheduled Maintenance *	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	12202	12938	12577	13017	12642	13017	12642	13992
11. Reserves After Maintenance (10-2)	2918	4072	2978	3822	2702	3468	2348	4075
12. Reserves After Maintenance (%) (11-2) x 100%	31.4	45.9	31.0	41.6	27.2	36.3	22.8	41.1
13. Inoperable Capability	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
14. Available Capability (10-13)	12197	12933	12572	13012	12637	13012	12637	13987
15. Available Reserves (14-2)	2913	4067	2973	3817	2697	3463	2343	4070
16. Available Reserves (%) (15-2) x 100%	31.4	45.9	31.0	41.5	27.1	36.3	22.8	41.0
17. Forced Outages *	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-7)	12197	12933	12572	13012	12637	13012	12637	13987
19. Actual Reserves (18-2)	2913	4067	2973	3817	2697	3463	2343	4070
20. Actual Reserves (%) (19-2) x 100%	31.4	45.6	31.0	41.5	27.1	36.3	22.8	41.0

*No information supplied

TABLE 1.D.19
Planned Capability by Type of Fuel - MW
CCD GROUP

Summer Capability

	NUCLEAR STEAM	COAL STEAM	OIL			NATURAL GAS			HYDRO		TOTAL CAPABILITY
			STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMB. TURB.	I.C.	CONVENT.	PUMPED STORAGE	
1980	-	7719	260	566	89		221	92	1		8948
% TOTAL	-	86.3	2.9	6.3	1.0		2.5	1.0	0.0		100
1981	792	8292	260	566	89		221	92	1		10313
% TOTAL	7.7	80.4	2.5	5.5	0.9		2.1	0.9	0.0		100
1982	792	8292	260	566	89		221	92	1		10313
% TOTAL	7.7	80.4	2.5	5.5	0.9		2.1	0.9	0.0		100
1983	792	8892	260	566	89		221	92	1		10913
% TOTAL	7.3	81.5	2.4	5.2	0.8		2.0	0.8	0.0		100
1984	792	8892	260	761	89		221	92	1		11108
% TOTAL	7.1	80.1	2.3	6.9	0.8		2.0	0.8	0.0		100
1985	792	8892	260	761	89		221	92	1		11108
% TOTAL	7.1	80.1	2.3	6.9	0.8		2.0	0.8	0.0		100
1986	792	10092	158	761	89		221	92	1		12206
% TOTAL	6.5	82.7	1.3	6.2	0.7		1.8	0.8	0.0		100
1987	792	10467	158	761	89		221	92	1		12581
% TOTAL	6.3	83.2	1.3	6.0	0.7		1.8	0.7	0.0		100
1988	792	10467	158	826	89		221	92	1		12646
% TOTAL	6.3	82.8	1.3	6.5	0.7		1.7	0.7	0.0		100
1989	792	10467	158	826	89		221	92	1		12646
% TOTAL	6.3	82.8	1.3	6.5	0.7		1.7	0.7	0.0		100

TABLE 1.D.20

Major Future Generating Capability Installations and (Removals)
CCD REGION

<u>STATION</u>	<u>UNIT TYPE</u>	<u>FUEL TYPE</u>	<u>NET CAPABILITY</u>	<u>IN-SERVICE DATE APRIL 79 "383" REPORT</u>	<u>IN-SERVICE DATE APRIL 80 "411" REPORT</u>
W. H. Zimmer #1	BWR	Uranium	807	1/80	1/81
Hayden	C.T.	#2 Oil	237	1/84	1/84
Poston #5	ST	Coal	375	1/87	1/87
Walnut 10-4	C.T.	#2 Oil	79	-	1/88
East Bend #2	ST	Coal	600	1/81	1/81
Killen #2	ST	Coal	600	10/82	10/82
East Bend #1	ST	Coal	600	10/84	10/85
Killen #1	ST	Coal	600	4/86	12/85
East Bend #3	ST	Coal	600	4/88	10/89

KENTUCKY GROUP (KY) ELECTRIC REGION 15HISTORICAL PERSPECTIVE

Electric Region 15 consists of the electric systems in the state of Kentucky excluding the Kentucky Power Co., a subsidiary of American Electric Power, and TVA. The major power suppliers in the region are Big Rivers Electric Corp., East Kentucky Power Cooperative, Kentucky Utilities Company. Data in this section are also included for the Henderson Kentucky and Owensboro, Kentucky municipal electric systems which are within the region.

All of the systems for which data are included are regular or liaison members of the ECAR organization. The two investor-owned utilities and the two municipal systems collectively serve about 489,000 residential customers, 60,000 commercial customers, 82,000, rural customers, and 3800 industrial customers. The two cooperative systems, Big Rivers and East Kentucky, serve 22 member cooperative systems.

The major transmission voltages in the Kentucky region are 138 kV and 161 kV. There is a 345 kV interconnection between Louisville Gas Electric Co., and the Ohio Valley Electric Corporation (OVEC). In addition to OVEC, the systems in Electric Region (ER) 15 have transmission ties with the Ohio Power Co., in ER 2-AEP; with the Central Illinois Public Service Co., and Electric Energy, Inc., in ER 17-ILLMO; with the Public Service Company of Indiana and the Southern Indiana Gas and Electric Co., in ER 16-IN; with Cincinnati Gas and Electric Co., in ER 14-CCD; and TVA in ER 11-TVA. The Kentucky region has historically been a summer peaking area. Shown below are the region's summer and winter peaks for the period 1977-1979.

Table 1E.1

Historical Peak Demand-MW
KENTUCKY REGION

		SUMMER			WINTER	
	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	4,432	<u>5,031</u>	4,859	4,687	<u>4,902</u>	4,688
1978	5,115	<u>5,045</u>	<u>5,139</u>	4,432	<u>5,045</u>	4,943
1979	4,881	5,013	<u>5,449</u>	4,823	<u>4,925</u>	<u>5,040</u>

Underline indicates seasonal peak.

The summer peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August.

The winter peak usually occurs in January, but it may occur in any winter month, depending on the combination of weather and economic activity in the region. The winter peak during the 1977-79 period was 3-8% less than the corresponding summer peak.

The following table shows the scheduled maintenance performed each period and also the capability unavailable because of forced outages or otherwise inoperable.

Table 1E.2

Scheduled Maintenance And Unavailable Capabilities
KENTUCKY REGION

	<u>SUMMER</u>			<u>WINTER</u>		
	<u>Scheduled</u>	<u>Other</u>	<u>Total</u>	<u>Scheduled</u>	<u>Other</u>	<u>Total</u>
	<u>Maintenance</u>	<u>Unavailable</u>	<u>Unavailable</u>	<u>Maintenance</u>	<u>Unavailable</u>	<u>Unavailable</u>
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
1977	0	318	318	23	796	819
1978	281	620	901	616	565	1,181
1979	55	553	608	900	1,134	2,034

The capability unavailable for reasons other than scheduled maintenance varied from 5-9% of the planned capability in summer and from 8-16% in winter.

The reserve margins for the 1977-79 period are shown below. The table indicating the effects of scheduled maintenance and other outages.

Table 1E.3

Historical Seasonal Reserves
KENTUCKY REGION

	<u>Summer</u>						
	<u>Peak</u>	<u>Total</u>	<u>Total</u>	<u>Available</u>	<u>Available</u>	<u>Actual</u>	<u>Actual</u>
	<u>Demand</u>	<u>Capability</u>	<u>Reserves</u>	<u>Capability</u>	<u>Reserves</u>	<u>Capability</u>	<u>Reserves</u>
	(MW)	(MW)	(%)	(MW)	(%)	(MW)	(%)
1977	5,031	6,014	19.5	6,014	19.5	5,696	13.2
1978	5,183	6,764	30.5	6,483	25.1	5,863	13.1
1979	5,449	6,981	28.1	6,926	27.1	6,373	17.0
	<u>Winter</u>						
1977	4,904	6,968	42.1	6,945	41.6	6,149	25.4
1978	5,045	7,220	43.1	6,604	30.9	6,039	19.7
1979	5,040	8,062	60.0	7,162	42.1	6,028	19.6

The reserve margins shown above indicate that for the 1977-79 period sufficient capability was available to meet the demand requirements in both the summer and winter periods.

Listed below are annual load and energy requirements for the 1977-79 period for the Kentucky Group.

Table 1E.4

Historical Energy, Peaks And Load Factors
KENTUCKY REGION

	<u>Energy Requirement</u>		<u>Summer</u>		<u>Winter</u>		<u>Actual</u>
	<u>(GWH)</u>	<u>(Growth-%)</u>	<u>Peak Demand</u>	<u>(Growth-%)</u>	<u>Peak Demand</u>	<u>(Growth-%)</u>	<u>Load Factor</u>
			<u>(MW)</u>		<u>(MW)</u>		<u>(%)</u>
1977	28,010	-	5,031	-	4,904	-	63.6
1979	28,543	1.9	5,183	3.0	5,045	2.9	62.9
1979	29,240	2.4	5,449	5.1	5,040	(0.1)	61.3
%Growth;1977-79		2.2		4.1		1.4	

Over the period, the energy requirements grew at a compound growth rate of 2.2%, the summer demand at 4.1% and the winter demand at 1.4%. The low growth rate of the energy requirements and the winter peak demand is consistent with that of other regions in ECAR. The summer demand was not as depressed in the Kentucky region as in other ECAR regions. The slow growth rate of the region show the effects of conservation, economic activity and typical weather conditions.

CURRENT PERSPECTIVE

The projected 1980 summer and winter non-coincident demands for the Kentucky Group are shown below:

Table 1E.5

Projected 1980 Seasonal Peak Demand*-MW
KENTUCKY REGION

<u>SUMMER</u>			<u>WINTER</u>		
June	July	Aug.	Dec.	Jan.	Feb.
5,391	5,669	5,780	5,560	5,919	5,661

*Non-coincident

The winter demand is projected to be 2.4% greater than the summer demand. This is the first seasonal shift of the peak since the 1977 and the area in the future is forecasted to be a winter peaking region. The 1980 winter planned capability is estimated to be 7583 MW and the non-coincident winter peak demand is projected to be 5918 MW, resulting in planned reserves of 1665 or 28%. After adjustments for scheduled receipts and deliveries total reserves are increased to 2469 MW or 41.7%.

In the ECAR ERA-411 report for the future 1980-89 the Kentucky Group does not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an overall Council indication of scheduled maintenance.

The estimate prepared for the 411 report, is based on the level of planned maintenance that is currently projected for the periods of heaviest load during the upcoming summer and winter seasons, i.e., five percent of total planned capability during the summer of 1980 and five percent of total planned capability during the winter of 1980/1981. The summer and winter 1980 reserve margins for the electric region are shown below.

Table 1E.6

1980 Reserve Margins*
KENTUCKY REGION

<u>SUMMER</u>				<u>WINTER</u>			
<u>Planned</u>		<u>Total</u>		<u>Planned</u>		<u>Total</u>	
<u>Reserves</u>		<u>Reserves</u>		<u>Reserves</u>		<u>Reserves</u>	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
1184	20.5	2014	34.8	1665	28.0	2469	41.7
		1666	28.8			2090	35.3

*Based on ERA Form 411

**5% of Total Installed Capability assumed - from ECAR ERA Form - 411 Report of scheduled outages.

The margins shown above have not been adjusted for unscheduled outages of capacity. If these outages do not exceed the maximum outages of the 1977-79 period, 9% of planned capacity during the summer period and 16% during the winter, then resultant actual reserves would be 1035 MW (18.0%) and 877 MW (14.8%) respectively.

The summer capability of the generating capacity planned in the Kentucky Region as of January 1, 1980 was 6964 MW. The capacity is shown below by type of fuel.

Table 1E.7

Planned Summer Capability, January 1, 1980 - (MW)
KENTUCKY REGION

	Coal		Oil		Natural Gas			Hydro Conv. P.S.	Total Capability
	Nu ST	ST	ST	GT	IC	ST	GT	IC	
	-	6586	64	132	2	-	92	-	6964
% Total	-	94.6	0.9	1.9	0.0	-	1.3	-	100.0

About 95% of the current capability is coal-fired steam capacity, less than 1% is oil-fired steam; and 1.9% is oil-fired combustion turbine capacity. There are no nuclear units installed in the Electric Region. There are no new units scheduled for service before December, 1980. The unit scheduled for December, 1980 is a 210 MW coal unit. A delay of this unit beyond the beginning of the winter 1980 peak period would reduce the winter 1980 available reserve to 31.8% which should be sufficient to supply the demand requirements after contingency outages. Also scheduled for the 1980 winter are two coal units totaling 984 MW in January, 1981.

If these two units were delayed past the peak period, the reserves would be reduced from 31.8% to 15.1%. If forced outages of 16% (maximum rate 1977-79 winter season) occurred the reserve margin would be deficient by 229 MW. Under these conditions, additional purchases would have to be made. The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown in Table 1E.8.

Table 1E.8

1980 Load Requirements
KENTUCKY REGION

	<u>Energy Requirement</u> (GWH)	<u>Summer</u> <u>Peak Demand</u> (MW)	<u>Winter</u> <u>Peak Demand</u> (MW)	<u>Actual</u> <u>Load Factor</u> (%)
	31700	5780	5918	61.0
% Growth 1980/89	8.4	6.1	17.4	

The 1980 summer and winter demands are projected to grow at considerably higher rates than they did during the 1977-79 period - (4.1% and 1n4%, respectively). The 1980 winter peak demand growth of 17.4% seems unrealistic in light of historical trends and conservation techniques, as does the 8.4% growth of the energy requirements. It may be that the 1980 data was extrapolated from a long term growth trend.

Future Perspective

The range of total reserves of the Kentucky Group for the periods 1981-1985 and 1986-1989 are shown in Table 1E.9.

Table 1E.9

Range of Total - Reserves - %
KENTUCKY REGION

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
37.4-43.3	31.4-46.2	38.6-46.2	30.4-38.9

As seen in Table 1E.9 the total reserves for summer range from 37-46%. Indications are that the Kentucky group will have no serious difficulties in meeting obligations. Total unavailable capability including scheduled maintenance averaged 9% of planned capability for the 1977-79 summer peak season and 19% for the winter peak season. Based on the stated assumptions the actual reserves are more than ample in all years of each period. Shown below are the projected growth rates of demand and capability for each period and the overall rates for 1981-89.

Table 1F.10Projected Energy and Demand Growth Rates
KENTUCKY REGION

	Energy Requirement		Summer Peak Demand		Winter Peak Demand		Actual Load Factor (%)
	(GWH)	(Growth-%)	(MW)	(Growth-%)	(MW)	(Growth-%)	
1981	33690	6.3	6187	7.0	6274	6.0	61.3
1982	35000	3.9	6511	5.2	6658	6.1	60.0
1983	36550	4.4	6843	5.1	7067	6.1	59.0
1984	37540	2.7	7187	5.0	7439	5.3	57.4
1985	38740	3.2	7530	4.8	7830	5.2	56.5
Growth 81-85		3.6		5.0		5.7	-
1986	40320	4.1	7881	4.7	8228	5.1	55.9
1987	42030	4.2	8248	4.6	8643	5.0	55.5
1988	43780	4.2	8633	4.7	9083	5.1	54.9
1989	45580	4.1	9026	4.6	9529	4.9	54.6
Growth 86-89		4.2		4.6		5.0	-

The 1981-1985 summer demands are projected to grow at a compound rate of 5.0%; 1986-1989, 4.6%; and overall, 1981-1989, at 4.8%. The winter demands are projected to grow at a rate of 5.7% during the 1981-85 period; 5.0% in the 1986-89 period; with an overall 1981-89 rate of 5.4%.

The summer demand growth rates for each time period are considerably greater than the 1977-1979 rate of 4.1%. Whereas, the ECAR region is projected to have a 1981-89 growth rate of only 3.8%. The winter demands growth rates also are considerably greater than the 1977-79 rate of 1.4%. The ECAR region's growth rate is projected to be only 3.9%.

The 1980 winter peak is projected to exceed the summer peak by 2.4%. The winter peak is projected to grow faster than the summer peak and to be 4.0% greater by 1985 and 5.6% greater by 1989.

The energy requirements are projected to grow at a rate of 3.6% from 1981-85; 4.2% from 1986-89. The overall growth rate is consistent with the projected growth rate of 3.8% for systems as a whole in ECAR.

The annual load factors are projected to decrease from 61.0% in 1980 to 54.6% in 1989. This is due to the high growth rate projected for the winter peak compared to the energy requirements. During the 1981-85 period, 7 coal-fired steam units are scheduled to be placed in service with a total capability of 3469 MW. Two older coal-fired units will be retired in 1985 with a present capability of 217 MW. In the period 1986-89, 4 coal-fired steam units are scheduled for installation with a total capability of 2140 MW. One coal-fired unit of 142 MW will be retired in 1987.

The summer and winter capability of units planned in the region during the period 1980-1989 is shown by type of fuel in Table 1E.19. Major generating unit additions during the period are given in Table 1E.20. The percentages of each type of capacity for the target years 1980, 1984 and 1989 are given below:

Table 1E.11

Planned Generating Capability by Type of Fuel - (%)

Winter Capability
KENTUCKY REGION

	<u>Nuclear</u> <u>Steam</u>	<u>Coal</u> <u>Steam</u>	<u>Oil</u> <u>ST</u>	<u>GT</u>	<u>IC</u>	<u>Nat. Gas</u> <u>GT</u>	<u>Hydro</u> <u>Conv.</u>	<u>Pumped</u> <u>Storage</u>	<u>Total</u> <u>Capability</u>
980	-	94.6	0.9	1.9	0.0	1.3	1.3	-	100.0
984	-	95.8	0.7	0.7	0.0	1.0	1.0	-	100.0
989	-	96.4	0.5	1.6	0.0	0.8	0.7	-	100.0

Currently, coal is the primary fuel for about 95% of the installed capacity of the region. This percentage is projected to increase to 96% by 1989.

There is only 64 MW of oil-fired steam capacity in the region and 136 MW of oil-fired combustion turbine capacity with only a slight increase in the combustion turbine capacity during the 1986-89 period. Natural gas capacity and hydroelectric plants are insignificant and will remain so throughout the 1981-89

period. There are no nuclear units installed in the region nor planned throughout the study period.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure and the material which appears in the final ECAR report is normally limited to those items which are of particular significance to the overall region. The appraisal is based on a careful analysis of various studies carried out by the ECAF Transmission System Performance Working Group under the direction of the Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions were considered during the course of the various studies referred to above. No localized transmission problems were apparent in the Kentucky group region.

The most recent ECAR appraisal studies were for Summer 1979 and Winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within the ECAR region would be maintained.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

Table 1E.12Emergency Transfer Capability - MW
KENTUCKY REGION

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979-80 Capability</u>
ECAR to MAAC	3300+	3300+
ECAR to NPCC (NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC (VACAR)	1250	1900*
ECAR from MAAC	2450	3300+
ECAR from NPCC (NYPP)	3300+	2900
ECAR from MAIN	4000	3800
ECAR from SERC (TVA)	2000	2100
ECAR from SERC (VACAR)	2700	2950*

*ETC Values determined with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No. 1. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No. 1 without suffering area-wide break-up and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to build the facilities shown. Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed as a result of excessive lag the certification process or as a result of difficulties in financing these projects, then appropriate short term operating procedures will need to be developed in order to maintain the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardized the reliability of the power supply in the affected area.

Table 1F.13Summer 1984 Emergency Transfer Capability - MW
KENTUCKY REGION

<u>Transfer</u>	<u>ETC</u> <u>(MW)</u>	<u>Transfer</u>	<u>ETC</u> <u>(MW)</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC	2900
ECVAR to MAIN	2900	ECAR from MAIN	4000
ECAR to SERC (TVA)	2500	ECAR from SERC (TVA)	3200
ECAR to SERC (VACAR)	2250	ECAR from SERC (VACAR)	5500

The following table is a list of proposed bulk power lines to be constructed by Kentucky Group companies. It includes internal transmission facilities as well as interconnections with utilities in other regions. Many of these interconnections will become critical to maintain reliability in the area and also provide routes for wheeling of large blocks of energy across council boundaries.

Table 1E.14
List of Proposed Bulk Power Lines
KENTUCKY REGION

<u>Line Ownership List</u>	<u>Terminals</u>	<u>Line Length</u>		<u>Planned Service Date</u>	<u>Nominal Voltage in kV</u>		<u>Remarks</u>
		<u>KM</u>	<u>MI</u>		<u>Oper</u>	<u>Dsgn</u>	
<u>Interconnections</u>							
EKPC KU	Brodhead / Brown-Pineville	16.1	10.0	Aug 87	345	345	10 mile D/C to loop Brodhead schedule is under study
TVA KU	Volunteer / Pineville	72.4	45.0	Nov 87	500	500	
IP&L KU	Patroit / Ghent	32.2	20.0	Oct 88	345	345	Increase interchange capability
PSI KU	Madison / Ghent	38.6	24.0	May 81	345	345	Convert from 138 kV deliver generator output provide area protection
KU TVA	Pocket / Phipps Bend	38.6	24.0	Nov 81	500	500	

Table 1E.14.1

List of Proposed Bulk Power Lines
KENTUCKY REGION

Line Ownership List	Terminals	Line Length		Planned Service Date	Nominal Voltage In kV		Remarks
		KM	MI		Oper	Dsgn	
EAST KENTUCKY POWER COOPERATIVE							
EKPC	Spurlock / Avon	93.3	58.0	Aug 80	345	345	
EKPC	Avon / J.K. Smith	32.2	20.0	Dec 83	345	345	
EKPC	J.K. Smith / Maggard	96.6	60.0	Aug 84	345	345	
KENTUCKY UTILITIES COMPANY							
KU	Brown / Elizabethtown	112.7	70.0	Apr 82	345	345	Via Lebanon
KU	Smith / Elizabethtown	104.6	65.0	Apr 82	345	345	Convert from 138 kV
KU	Ghent / West Frankfort	64.4	40.0	Dec 82	345	345	
KU	Pocket / Pineville	70.8	44.0	Nov 83	500	500	
KU	Brown / Pineville	165.0	102.5	Nov 84	345	345	2nd CKT via Alcalde Station
KU	West Frankfort / Brown	46.6	29.0	Apr 86	345	345	
KU	Walker / Smith	75.6	47.0	May 86	345	345	
KU	Hancock / Smith-Elizabethtown	16.1	10.0	Aug 87	345	345	Loop into Hancock on D/C Towers
KU	Walker / Green River	38.6	24.0	May 90	345	345	
KU	Hancock / Elizabethtown	80.5	50.0	Dec 90	345	345	
KU	Hancock / Green River	74.0	45.0	Dec 90	345	345	
LOUISVILLE GAS & ELECTRIC COMPANY							
LG&E	Blue Lick / Mill Creek	19.3	12.0	Jun 81	345	345	
LG&E	Blue Lick / Middletown	30.5	19.0	Jun 81	345	345	
LG&E	Trimble Co. / Middletown-Clifty Creek	0.0	0.0	May 84	345	345	
LG&E	Fairmount / Mill Ck.-Middletown	0.0	0.0	May 85	345	345	Take existing Mill Creek-Middletown 345 kV in and out of Fairmount
LG&E	Trimble Co. / Northside	41.8	26.0	May 86	345	345	
LG&E	Trimble Co. / Northside	41.8	26.0	May 88	345	345	

Table 1E.15

Historical Capability (MW) and Reserves (MW and Percent)
KENTUCKY REGION

	Summer July 1977	Winter Jan 1978	Summer Aug 1978	Winter Jan 1979	Summer Aug 1979	Winter Feb 1980
1. Planned Capability	6284.	6481.	6587.	6997.	6892.	7163.
2. Peak Demand	5031.	4904.	5183.	5045.	5449.	5040.
3. Planned Reserves (1-2)	1253.	1577.	1404.	1952.	1443.	2123.
4. Planned Reserves (%) ($3 \div 2 \times 100\%$)	24.9	32.2	27.1	33.7	26.5	42.1
5. Net Transactions (Imports - Exports)	-270.	487.	177.	223.	89.	899.
6. Total Capability (1+5)	6014.	6968.	6764.	7220.	6981.	8062.
7. Total Reserves (6-2)	983.	2064.	1581.	2175.	1532.	3022.
8. Total Reserves (%) ($7 \div 2 \times 100\%$)	19.5	42.1	30.5	43.1	28.1	60.0
9. Scheduled Maintenance	0.	23.	281.	616.	55.	900.
10. Capability after Maintenance (6-9)	6014.	6945.	6483.	6604.	6926.	7162.
11. Reserves after Maintenance (10-2)	983.	2041.	1300.	1559.	1477.	2122.
12. Reserves after Maintenance (%) ($11 \div 2 \times 100\%$)	19.5	41.6	25.1	30.9	27.1	42.1
13. Inoperable Capability (Included in 17)	0.	0.	0.	0.	0.	0.
14. Available Capability (10-13)	6014.	6945.	6483.	6604.	6926.	7162.
15. Available Reserves (14-2)	983.	2041.	1300.	1559.	1477.	2122.
16. Available Reserves (%) ($15 \div 2 \times 100\%$)	19.5	41.6	25.1	30.9	27.1	42.1
17. Forced Outages	318.	796.	620.	565.	553.	1134.
18. Actual Capability after Forced Outages (14-17)	5696.	6149.	5863.	6039.	6373.	6028.
19. Actual Reserves (18-2)	665.	1245.	680.	994.	924.	988.
20. Actual Reserves (%) ($19 \div 2 \times 100\%$)	13.2	25.4	13.1	19.7	17.0	19.6

Table 1E.16

Current Capability (MW) and Reserves (MW and Percent)
KENTUCKY REGION

	1980	
	Summer	Winter
1. Planned Capability	6964.	7583.
2. Peak Demand	5780.	5918.
3. Planned Reserves (1-2)	1184.	1665.
4. Planned Reserves (%) ($3 \div 2 \times 100\%$)	20.5	28.1
5. Net Transactions (Imports - Exports)	830.	804.
6. Total Capability (1+5)	7794.	8387.
7. Total Reserves (6-2)	2014.	2469.
8. Total Reserves (%) ($7 \div 2 \times 100\%$)	34.8	41.7
9. Scheduled Maintenance ^{1/}	348.	379.
10. Capability after Maintenance (6-9)	7446.	8008.
11. Reserves after Maintenance (10-2)	1666.	2090.
12. Reserves after Maintenance (%) ($11 \div 2 \times 100\%$)	28.8	35.3
13. Inoperable Capability *No data provided	0.	0.
14. Available Capability (10-13)	7446.	8008.
15. Available Reserves (14-2)	1666.	2090.
16. Available Reserves (%) ($15 \div 2 \times 100\%$)	28.8	35.3
17. Forced Outages *No data provided	0.	0.
18. Actual Capability after Forced Outages (14-17)	7446.	8008.
19. Actual Reserves (18-2)	1666.	2090.
20. Actual Reserves (%) ($19 \div 2 \times 100\%$)	28.8	35.3

^{1/} 5% of total planned capability assumed by
ERA-Form ECAR ERA-411 Report.

Table 1E.17

Future Capability (MW) and Reserves (MW and Percent)
KENTUCKY REGION

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	8536.	8462.	8530.	8956.	8960.	8905.	9783.	10307.	10168.	11085.
2. Peak Demand	6187.	6274.	6511.	6658.	6843.	7087.	7187.	7439.	7530.	7876.
3. Planned Reserves (1-2)	2349.	2188.	2019.	2296.	2117.	1818.	2596.	2868.	2638.	3255.
4. Planned Reserves (%) (3÷2)×100%	38.0	34.9	31.0	34.5	30.9	25.7	36.1	38.6	35.0	41.6
5. Net Transactions (Imports-Exports)	332.	480.	481.	481.	442.	399.	387.	381.	373.	363.
6. Total Capability (1+5)	8868.	8942.	9011.	9437.	9402.	9284.	10170.	10688.	10541.	11448.
7. Total Reserves (6-2)	2681.	2668.	2500.	2779.	2559.	2217.	2983.	3249.	3011.	3618.
8. Total Reserves (%) (7÷2) × 100%	43.3	42.5	38.4	41.7	37.4	31.4	41.5	43.7	40.0	46.2
9. Scheduled Maintenance*	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
10. Capability After Maintenance (6-9)	8868.	8942.	9011.	9437.	9402.	9284.	10170.	10688.	10541.	11448.
11. Reserves After Maintenance (10-2)	2681.	2668.	2500.	2779.	2559.	2217.	2983.	3249.	3011.	3618.
12. Reserves After Mainte- nance (%) (11÷2) × 100%	43.3	42.5	38.4	41.7	37.4	31.4	41.5	43.7	40.0	46.2
13. Inoperable Capability*	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14. Available Capability (10-13)	8868.	8942.	9011.	9437.	9402.	9284.	10170.	10688.	10541.	11448.
15. Available Reserves (14-2)	2681.	2668.	2500.	2779.	2559.	2217.	2983.	3249.	3011.	3618.
16. Available Reserves (%) (15÷2) × 100%	43.3	42.5	38.4	41.7	37.4	31.4	41.5	43.7	40.0	46.2
17. Forced Outages *	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18. Actual Capability After Forced Outages (14-17)	8868.	8942.	9011.	9437.	9402.	9284.	10170.	10688.	10541.	11448.
19. Actual Reserves (18-2)	2681.	3668.	2500.	2779.	2559.	2817.	2983.	3249.	3011.	3618.
20. Actual Reserves (%) (19÷2) × 100%	43.3	42.5	38.4	41.7	37.4	39.4	41.5	43.7	40.0	46.2

* No data provided.

Table 1E.18

Future Capability (MW) and Reserves (MW and Percent)
KENTUCKY REGION

	1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	11163.	11085.	11087.	11658.	12232.	12153.	12232.	12153.
2. Peak Demand	7881.	8228.	8241.	8643.	8633.	9083.	9026.	9529.
3. Planned Reserves (1-2)	3282.	2857.	2846.	3015.	3599.	3070.	3206.	2624.
4. Planned Reserves (%) ($3 \div 2 \times 100\%$)	41.6	34.7	34.5	34.9	41.7	33.8	35.5	27.5
5. Net Transactions (Imports - Exports)	357.	343.	339.	321.	319.	298.	298.	274.
6. Total Capability (1+5)	11520.	11428.	11426.	11979.	12551.	12451.	12530.	12427.
7. Total Reserves (6-2)	3639.	3200.	3185.	3336.	3918.	3368.	3504.	2898.
8. Total Reserves (%) ($7 \div 2 \times 100\%$)	46.2	38.9	38.6	38.6	45.4	37.1	38.0	30.4
9. Scheduled Maintenance*	0.	0.	0.	0.	0.	0.	0.	0.
10. Capability after Maintenance (6-9)	11520.	11428.	11426.	11979.	12551.	12451.	12530.	12427.
11. Reserves after Maintenance (10-2)	3639.	3200.	3185.	3336.	3918.	3368.	3504.	2898.
12. Reserves after Maintenance (%) ($11 \div 2 \times 100\%$)	46.2	38.9	38.6	38.6	45.4	37.1	38.8	30.4
13. Inoperable Capability*	0.	0.	0.	0.	0.	0.	0.	0.
14. Available Capability (10-13)	11520.	11428.	11426.	11979.	12551.	12451.	12530.	12427.
15. Available Reserves (14-2)	3639.	3200.	3185.	3336.	3918.	3368.	3504.	2898.
16. Available Reserves (%) ($15 \div 2 \times 100\%$)	46.2	38.9	38.6	38.6	45.4	37.1	38.8	30.4
17. Forced Outages*	0.	0.	0.	0.	0.	0.	0.	0.
18. Actual Capability after Forced Outages (14-17)	11520.	11428.	11426.	11979.	12551.	12451.	12530.	12427.
19. Actual Reserves (18-2)	3639.	3200.	3185.	3336.	3918.	3368.	3504.	2898.
20. Actual Reserves (%) ($19 \div 2 \times 100\%$)	46.2	38.9	38.6	38.6	45.4	37.1	38.8	30.4

*No data provided.

Table 1E.19

Installed Capability as of January 1, BY Type of Fuel - MW
KENTUCKY REGION
Summer Capability

Electric Region 15-KY	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convent.	Pumped Storage	
1980	-	6586	64	132	2	-	92	-	88	-	6964
% Total	-	94.6	0.9	1.9	0.0	-	1.3	-	1.3	-	100.0
1981	-	6796	64	132	2	-	92	-	88	-	7174
% Total	-	94.7	0.9	1.9	0.0	-	1.3	-	1.2	-	100.0
1982	-	8161	64	132	2	-	92	-	88	-	8539
% Total	-	95.6	0.7	1.6	0.0	-	1.1	-	1.0	-	100.0
1983	-	8159	64	132	2	-	92	-	88	-	8537
% Total	-	95.6	0.7	1.6	0.0	-	1.1	-	1.0	-	100.0
1984	-	8589	64	132	2	-	92	-	88	-	8967
% Total	-	95.8	0.7	1.5	0.0	-	1.0	-	1.0	-	100.0
1985	-	9412	64	132	2	-	92	-	88	-	9790
% Total	-	96.1	0.7	1.4	0.0	-	0.9	-	0.9	-	100.0
1986	-	9797	64	132	2	-	92	-	88	-	10175
% Total	-	96.3	0.6	1.3	0.0	-	0.9	-	0.9	-	100.0
1987	-	10792	64	132	2	-	92	-	88	-	11170
% Total	-	96.6	0.6	1.2	0.0	-	0.8	-	0.8	-	100.0
1988	-	11301	64	197	2	-	92	-	88	-	11744
% Total	-	96.2	0.5	1.7	0.0	-	0.8	-	0.8	-	100.0
1989	-	11796	64	197	2	-	92	-	88	-	12239
% Total	-	96.4	0.5	1.6	0.0	-	0.8	-	0.7	-	100.0

Table 1E.19.1

Installed Capability as of January 1, BY Type of Fuel - MW
KENTUCKY REGION
Winter Capability

Electric Region 15 - KY	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convent.	Pumped Storage	
1980	-	6619	65	144	2	-	107	-	67	-	7004
% Total	-	94.5	0.9	2.1	0.0	-	1.5	-	1.0	-	100.0
1981	-	6829	65	144	2	-	107	-	67	-	7214
% Total	-	94.7	0.9	2.0	0.0	-	1.5	-	0.9	-	100.0
1982	-	8192	65	144	2	-	107	-	67	-	8577
% Total	-	95.5	0.8	1.7	0.0	-	1.2	-	0.8	-	100.0
1983	-	8186	65	144	2	-	107	-	67	-	8571
% Total	-	95.5	0.8	1.7	0.0	-	1.2	-	0.8	-	100.0
1984	-	8615	65	144	2	-	107	-	67	-	9000
% Total	-	95.7	0.7	1.6	0.0	-	1.2	-	0.8	-	100.0
1985	-	9437	65	144	2	-	107	-	67	-	9822
% Total	-	96.1	0.6	1.5	0.0	-	1.1	-	0.7	-	100.0
1986	-	9820	65	144	2	-	107	-	67	-	10205
% Total	-	96.2	0.6	1.4	0.0	-	1.1	-	0.7	-	100.0
1987	-	10815	65	144	2	-	107	-	67	-	11200
% Total	-	96.5	0.6	1.3	0.0	-	1.0	-	0.6	-	100.0
1988	-	11323	65	209	2	-	107	-	67	-	11773
% Total	-	96.2	0.5	1.8	0.0	-	0.9	-	0.6	-	100.0
1989	-	11818	65	209	2	-	107	-	67	-	12268
% Total	-	96.3	0.5	1.7	0.0	-	0.9	-	0.6	-	100.0

Table 1E.20

Major Future Generating Capability
Installations and (Removals)
KENTUCKY REGION

System	Station	Unit Type	Fuel Type	Net		In-Service	In-Service
				Capacity - MW		Date	Date
				Summer	Winter	April 79 "383" Report	April 80 "411" Report
BIRI	Green 2	ST	Coal	210	210	12/80	12/80
EKPC	H.L. Spurlock #2	ST	Coal	484	484	1/81	1/81
KU	Ghent 3	ST	Coal	500	500	6/81	6/81
LG&E	Mill Creek 4	ST	Coal	495	495	6/81	6/81
KU	Ghent 4	ST	Coal	500	500	1/83	1/83
LG&E	Trimble Cty. 1	ST	Coal	495	495	6/84	6/84
BIRI	D.B. Wilson 1	ST	Coal	395	395	7/85	7/85
EKPC	J.K. Smith	ST	Coal	600	600	1/85	1/85
LG&E	Cane Runlt 2	ST	Coal	(215)	(217)	6/85	6/85
EKPC	J.K. Smith	ST	Coal	600	600	1/86	1/86
BIRI	D.B. Wilson 2	ST	Coal	395	395	-	1/86
LG&E	Cane Run 3	ST	Coal	(141)	(142)	6/87	6/87
KU	Hancock Cty. 1	ST	Coal	650	650	10/85	10/87
LG&E	Trimble Cty. 2	ST	Coal	495	495	6/86	6/88
KU	Hancock Cty. #2	ST	Coal	650	650	10/87	1/

1/ Not shown on April 80 "411" Report

INDIANA REGION - (IN)

Electric Region 16Historical Perspective

Electric Region 16 consists of all Indiana electric systems, except for the Indiana and Michigan Electric Co., which is part of the AEP system, Electric Region - 2, and the Indiana-Kentucky Corporation--a subsidiary of OVEC, which owns a 1300 MW generating plant at Madison, Indiana. Data are included in this section for the following electric systems: Hoosier Energy Division, Indiana Statewide Rural Electric Cooperative, Inc.; Indianapolis Power and Light Co.; Northern Indiana Public Service Co.; Public Service Co., of Indiana; Richmond, Indiana Municipal; and Southern Indiana Gas and Electric Co.

All of the systems for which data are included in the following are regular or liaison members of the ECAR organization.

The utilities in the Indiana Region serve about 1.3 million customers, of which 1.1 million are residential customers; 135,000 are commercial customers; and 13,000 are industrial customers. The major transmission voltage in the region is 138 kV, with 345 kV ties to the Indiana and Michigan Electric Co., Electric Region - 2, and the Commonwealth Edison Co., Electric Region - 6. There are also transmission ties with the Big Rivers Electric Corporation and the Louisville Gas and Electric Co., in Electric Region - 15.

The Wabash Valley Power Association (WVPA) was formed in 1963 to represent its member systems in all wholesale power cost matters. Its members consists of 22 distribution cooperatives, all but two of which are in Indiana. The WVPA has a 17 percent interest (192 MW) in the Marble Hill nuclear plant (1130 MW) under construction by the Public Service Company of Indiana and scheduled for October 1982. WVPA has scheduled the delivery of its share of the unit to Northern Indiana Public Service and to Public Service of Indiana; and the loads of the WVPA member cooperatives are included in the load data of those two companies.

Shown below are the summer and winter peak demands of the Indiana region for the period 1977-79:

Table 1F.1

HISTORICAL PEAK DEMAND * - MW
Indiana Region

	- S u m m e r -				- W i n t e r -		
	<u>Jun.</u>	<u>Jul.</u>	<u>Aug.</u>	<u>Sep.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	7426	<u>8340</u>	7947	8007	7681	<u>8169</u>	7556
1978	8243	8247	8085	<u>8254</u>	7460	<u>8348</u>	8194
1979	7688	8084	<u>8654</u>	7779	7605	7693	<u>7809</u>

NOTE: Underline indicates seasonal peak.

* Non-coincident

The summer peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August; but in 1978, it occurred in September.

The winter peak usually occurs in January; but it may occur in any winter month, depending upon the combination of weather and economic activity, and it occurred in February in the winter of 1979-80 in the region. The winter peak during the 1977-79 period was 2.1% and 9.8% less than the corresponding summer peak in 1977 and 1979, respectively, but was 1.1% greater in 1978. Since the summer and winter peaks are nearly equal, scheduled maintenance is performed during both peak seasons. The following table shows the scheduled maintenance performed each period and also the capability unavailable because of forced outages, or otherwise inoperable.

Table 1F.2

SCHEDULED MAINTENANCE AND UNAVAILABLE CAPABILITIES
Indiana Region

<u>- S u m m e r</u>			<u>- W i n t e r -</u>		
<u>Scheduled</u> <u>Maintenance</u> (MW)	<u>Other</u> <u>Unavailable</u> (MW)	<u>Total</u> <u>Unavailable</u> (MW)	<u>Scheduled</u> <u>Maintenance</u> (MW)	<u>Other</u> <u>Unavailable</u> (MW)	<u>Total</u> <u>Unavailable</u> (MW)
1977	83	1626	1032	1918	2950
1978	427	1955	555	1318	1873
1979	586	1673	1375	1527	2902

The capability unavailable for reasons other than scheduled maintenance varied from 14 - 18% of the planned capability in summer and from 12-19% in winter.

The reserve margins for the 1977-79 seasonal periods are shown below, considering the effects of scheduled maintenance and other outages.

Table 1F.3

HISTORICAL SEASONAL RESERVES
Indiana Region

<u>- S u m m e r -</u>							
<u>Peak</u> <u>Demand</u> (MW)	<u>Total</u> <u>Capability</u> (MW)	<u>Total</u> <u>Reserves</u> (%)	<u>Capability</u> <u>After</u> <u>Maintenance</u> (MW)	<u>Available</u> <u>Reserves</u> (%)	<u>Actual</u> <u>Capability</u> (MW)	<u>Actual</u> <u>Reserves</u> (%)	
1977	8340	10307	23.6	10224	22.6	8598	3.1
1978	8359	11381	36.2	10954	31.0	8999	7.7
1979	8654	11703	35.2	11117	28.5	9444	9.1
<u>- W i n t e r -</u>							
1977	8172	11654	42.6	10622	30.0	8704	6.5
1978	8348	10909	30.7	10354	24.0	9036	8.2
1979	7852	11692	48.9	10317	31.4	8790	11.9

The reserve margins shown above indicate that for the 1977-79 period sufficient capability was available to meet the demand requirements in both the summer and winter periods, after taking into account both scheduled and forced outages, and still have ample available reserves to meet other contingencies.

Shown in Table 1F.4 are the Indiana Region's energy requirements, summer and winter demands, and annual load factors for the 1977-79 period.

Table 1F.4

HISTORICAL ENERGY, PEAKS * AND LOAD FACTORS
Indiana Region

	<u>Energy Requirement</u>		<u>Summer Demand</u>		<u>Winter Demand</u>		<u>Annual Load Factor</u>
	(GWH)	(%)	(MW)	(%)	(MW)	(%)	(%)
1977	46192	-	8340	-	8172	-	63.2
1978	46967	1.7	8359	0.2	8348	2.2	64.1
1979	48604	3.5	8654	3.5	7852	(5.9)	64.1
% Growth 1977-79		2.6		1.9		(2.0)	

* Non-Coincident

Over the period, the energy requirements grew at a compound growth rate of 2.6%, the summer demand at 1.9%, and the winter demand at a decreased rate of 2.0%.

The large decrease in the winter peak from 1978-79 is evident in other ECAR systems which indicates it is probably weather-related.

Current Perspective

The projected 1980 summer and winter non-coincident Indiana Region peak demands are shown below:

Table 1F.5

PROJECTED 1980 SEASONAL PEAK DEMAND - MW
Indiana Region

<u>S u m m e r</u>			<u>W i n t e r</u>		
<u>Jun.</u>	<u>Jul.</u>	<u>Aug.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
8700	9126	<u>9311</u>	8896	9403	9084

* Non-coincident

The 1980 winter peak is projected to be slightly greater than the summer peak. Historically, the region has peaked in either season. However, the projections for the period 1981-89 indicate that the region will be winter peaking throughout the period.

The 1980 summer installed capability of the Indiana Region is estimated to be 11,722 MW and the summer non-coincident peak demand is projected to be 9315 MW, resulting in planned reserves of 2,407 MW or 25.8%. After adjustments for scheduled receipts and deliveries, total reserves are increased to 2,610 MW or 28.0%.

In the ECAR ERA-411 report for the future 1980-1989, the Indiana Region companies do not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an indication of planned maintenance for the entire region.

The estimate prepared for the ERA-411 report is based upon the level of planned maintenance that is currently projected for the periods of heaviest load demand during the upcoming summer and winter seasons; i.e., five percent of total planned capability during the summer of 1980 and five percent of total planned capability during the winter of 1980/81.

The summer and winter 1980 reserve margins for the electric region are shown below:

Table 1F.6

RESERVE MARGINS *
Indiana Region

1980 Summer Reserve Margin						1980 Winter Reserve Margin					
Planned		Total		Available		Planned		Total		Available *	
Reserves		Reserves		Reserves **		Reserves		Reserves		Reserves	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
2407	25.8	2610	28.0	2024	21.7	2490	26.5	2648	28.2	2053	21.8

* Based upon ERA-411 Form.

** 5% of Total installed capability assumed from ECAR ERA-411 Form, Report of Scheduled Outages.

The summer capability of the generating facilities installed in the Indiana Region area in 1980 is 11,732 MW. The capability breakdown by fuel type is shown below:

Table 1F.7

1980 PLANNED SUMMER CAPABILITY - (MW)
Indiana Region

- 1980 Summer Installed Capability in MW -								
Nuclear	Coal	- Oil -			Gas	Hydro	Pumped	Total
Steam	Steam	ST	GT	IC	GT	Convent	Storage	Capability
-	10671	408	532	32	24	65	-	11732
% of Total	91.0	3.5	4.5	0.3	0.2	0.5	-	100.0

Over 90% of the current capacity is coal-fired steam capacity; 3.5% oil-fired steam; and 4.5% oil-fired combustion turbine capacity. There are no nuclear units installed in the Electric Region. No new generating units are scheduled to be installed in the region until May 1981.

The projected 1980 energy requirements, summer and winter demand requirements, and annual load factor for the region are shown below:

Table 1F.8

1980 LOAD REQUIREMENTS
Indiana Region

	<u>Energy Requirement</u> (GWH)	<u>Summer Peak</u> (MW)	<u>Winter Demand</u> (MW)	<u>Annual Load Factor</u> (%)
	52120	9315	9403	63.1
% Growth 1980/79	7.3	7.6	19.8	-

The 1980 projected summer and winter demands are estimated to grow at considerably higher rates than they did during the 1977-79 period -- 1.9% and (2.0)%, respectively.

The projected 1980 energy requirements growth rate of 7.3% over 1979 requirements is considerably greater than the historic 1977-79 rate of 2.6%.

These 1980 projected figures for energy and peak demands seem highly inflated and unrealistic based on historical trends and conservation techniques. It may be that the 1980 data was extrapolated from long-term growth trends and is not indicative of short term growth rates.

If reduced demands do develop in 1980, the reserve situation in the region will be improved for the study period. Delays of future critical bulk power transmission facilities that will not be in service when needed are required to be reported under Item 5-6 of the ERA-411 report. In the April 1, 1980, ECAR report, the Public Service of Indiana's Gibson-Dresser-Cayuga 345 kV transmission line is reported as having been delayed from its scheduled in-service date of December 31, 1977, to a

tentative date of June 30, 1980, for the Gibson-Dresser section and September 30, 1980, for the Dresser-Cayuga section. The line was originally scheduled with the third 650 MW generating unit at the Public Service of Indiana's Gibson Plant. The delay was caused by litigation to acquire the necessary right-of-way. The delay in completion of the line will necessitate a reduction in the generation level at the Gibson plant in order to maintain system reliability for certain single contingency situations.

Future Perspective

The range of total reserves for the Indiana Region for the periods 1981-85 and 1986-89 are tabulated below:

Table 1F.9

RANGE OF TOTAL RESERVES Indiana Region

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
27.1 - 48.1	28.6 - 46.9	40.0 - 42.5	29.1 - 35.6

The available reserves have been determined after deducting a nominal amount (5% of the planned capability) from the reserve margin each period. No adjustments have been made for forced outages, as these are unknown. However, if the maximum outage rates of 18% and 19% which occurred during the 1977-79 summer and winter peak periods, respectively, are deducted from the available reserves, actual reserve margins would become negative in the summer of 1981 and 1982 by 61 MW and 12 MW, respectively; and by 147 MW in the winter of 1981. Positive reserve margins result in all other years except for the winter of 1989 which has a deficit of 227 MW. These amounts are not large, and supplemental power receipts should be available to offset the deficits if they are needed.

Shown below are the projected growth rates of demand and energy for each period and the overall rates for 1981-89:

Table 1F.10

PROJECTED ENERGY AND DEMAND GROWTH RATES
Indiana Region

	<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	(GWh)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1981	55,030	5.6	9,742	4.6	9,949	5.8	63.1
1982	57,720	4.9	10,160	4.3	10,523	5.8	62.6
1983	60,520	4.8	10,636	4.7	11,129	5.8	62.1
1984	63,710	5.3	11,099	4.4	11,720	5.3	61.9
1985	67,290	5.6	11,544	4.0	12,370	5.5	62.1
% Growth 81-85		5.2		4.3		5.6	
1986	71,040	5.6	12,020	4.1	13,036	5.4	62.2
1987	74,640	5.1	12,489	3.9	13,603	4.3	62.6
1988	78,470	5.1	12,984	4.0	14,436	6.1	61.9
1989	82,300	4.9	13,503	4.0	15,189	5.2	61.8
% Growth 86-89		5.0		4.0		5.2	
% Growth 81-89		5.2		4.2		5.4	

The 1981-1985 summer demands are projected to grow at a compound rate of 4.3%; 1986-1989, 4.00%; and overall, 1981-1989, at 4.2%. The winter demands are projected to grow 5.6% during the 1981-85 period; 5.2% during the 1986-89 period; with an overall 1981-89 growth rate of 5.4%.

The summer and winter demand growth rates of each period is considerably greater than the 1977-79 rates of 1.9% and (-2.0)%. These rates are also considerably greater than the ECAR region as a whole, which is projected to have a 1981-89 growth rate of 3.8% for the summer demands and a 3.9% growth rate for the winter demands. However, if the projected demands are greater than those which do occur, the reserve margins will be better than shown in the preceding tables.

The winter peak is projected to grow faster than the summer peak and to be 7.2% greater by 1985 and 12.5% greater by 1989.

The energy requirements are projected to grow at a rate of 5.2% from 1981-85; 5.0% from 1986-89; and at an overall rate of 5.2% from 1981-89.

These rates are considerably greater than the 1977-79 rate of 2.6% and the 1981-89 growth rate of 3.8% for the systems as a whole in ECAR.

The annual load factors are projected to decrease slightly from 63.1% in 1981 for 61.8% in 1989.

During the 1981-85 period, six coal-fired steam units are scheduled to be placed in service with a total capability of 2,573 MW. Two nuclear units -- Marble Hill No's. 1 and 2, 938 MW each, are also scheduled for installation in October 1982 and January 1984.

In the period 1986-89, five coal-fired units are scheduled for installation with a total capability of 2,650 MW. Also scheduled in this period is the Bailly Nuclear unit, 644 MW, for installation in October 1987.

The summer and winter capability of units installed in the region during the period 1980-1989 is shown by type of fuel in Table 1F.18. Major generating unit additions during the period are given in Table 1F.19. The percentages of each type of capacity for the target years 1980, 1984, and 1989, are given below:

Table 1F.11

PLANNED GENERATING CAPABILITY BY TYPE OF FUEL - (%)
Indiana Region

	Nuclear Steam	Coal Steam	<u>- O i l -</u>			Natural Gas	Hydro Convent	Pumped Storage	Total Capability
			ST	GT	IC				
1980	-	91.0	3.5	4.5	0.3	0.2	0.5	-	100.0
1984	6.4	86.1	2.5	4.2	0.2	0.2	0.4	-	100.0
1989	13.5	80.7	1.8	3.4	0.2	0.1	0.3	-	100.0

Currently, coal is the primary fuel for about 91% of the planned capacity of the region. This percentage will decrease to 81% due to the addition of three nuclear units in the period. There are 408 MW of oil-fired steam capacity in the region and 532 MW of oil-fired combustion turbine capacity, with only a slight increase planned in the combustion turbine capacity during the 1981-89 period. Natural gas and hydroelectric plants are insignificant and will remain so throughout the 1981-89 period.

There are three nuclear units planned, which will increase the nuclear capacity in the region from none in 1980 to 2,520 MW or 13.5% of the total capability in 1989.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure, and the material which appears in the final ECAR report is normally limited to those items which are of particular significance to the overall region. The appraisal is based on a careful analysis of various studies carried out by the ECAR Transmission System Performance Working Group under the direction of the Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions were considered during the course of the various studies referred to above, and the following operating procedures were developed:

PSI--Greentown Transformer

The outage of the Greentown 765/138 kV transformer may, for certain system conditions, overload the 138 kV winding of the Kokomo 230/138/69 kV transformer. To remedy this situation, the following operating procedure has been established. Upon loss of the Greentown 765/138 kV transformer, the Greentown 138 kV bus is split, isolating the PSI 138 kV circuits from the IME 138 kV circuits. To further reduce the Kokomo transformer loading, the Miami-Wabash peaking generation (70 MW) may be placed on line.

The most recent ECAR appraisal studies were for the Summer 1979 and the Winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

Table IF.12

EMERGENCY TRANSFER CAPABILITY - MW Indiana Region

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979-80 Capability</u>
ECAR to MAAC	3300 *	3300 *
ECAR to NPCC (MYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC (VACAR)	1250	1900 *
ECAR from MAAC	2450	3300 *
ECAR from NPCC (MYPP)	3300 *	2900
ECAR from MAIN	4000 *	3800
ECAR from SERC (TVA)	2000	2100
ECAR from SERC (VACAR)	2700	2950 *

* ETC Values determined with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No. 1. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No. 1 without suffering area-wide breakup and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to provide the facilities shown. Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed as a result of excessive lag in the certification process or as a result of difficulties in financing these projects due to inadequate rate relief, then appropriate short-term operating procedures will need to be developed in order to maintain, to the greatest extent possible, the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, are as follows:

Table 1F.13

SUMMER 1984 EMERGENCY TRANSFER CAPABILITY - MW
Indiana Region

<u>Transfer</u>	<u>ETC MW</u>	<u>Transfer</u>	<u>ETC MW</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC (NYPP)	2900
ECAR to MAIN	2900	ECAR from MAIN	4000 *
ECAR to SERC (TVA)	2500	ECAR from SERC (TVA)	3200
ECAR to SERC (VACAR)	2250	ECAR from SERC (VACAR)	5500 *

The following table is a list of proposed bulk power lines to be constructed by Indiana Region companies. It includes internal transmission facilities as well as interconnections with utilities in other regions. Many of these interconnections will become critical, since the Indiana Region's low reserve margins in portions of the study period indicate a reliance on capacity imports and therefore may make the wheeling of large blocks of energy through the system necessary.

Table 1F.14LIST OF PROPOSED BULK POWER LINES
Indiana RegionInterconnections

Line Ownership List	Terminals	Line Length		Planned Service Date	Nominal Voltage in KV		Remarks
		KM	MI		Oper	Dsgn	
HED PSI	Merom / Gibson-Dresser	3.2	2.0	Jun '80	345	345	Loop into Merom Deliver Generation Output
HED PSI	Ramsey / Gibson-Speed	0.0	0.0	Sep '80	345	345	Loop into Ramsey Provide Area Support
PSI KU	Madison / Ghent	38.6	24.0	May '81	345	345	Convert from 138 kV Deliver Generator Output Provide Area Protection
IP&L PSI	Petersburg / Gibson-Bedford	16.1	10.0	Aug '82	345	345	Coordinated Agreement Loop into Petersburg Deliver Generator Output
AEP PSI	Jefferson / Marble Hill	24.1	15.0	Jan '84	765	765	Deliver Generator Output
PSI AEP	Gwynneville / Jefferson-Greentown	0.0	0.0	Jan '84	765	765	Loop into Gwynneville Deliver Generator Output
IP&L KU	Patriot / Ghent	32.2	20.0	Oct '88	345	345	Increase Interchange Capability
PSI LG&E	Speed / Northside	11.2	7.0	Jun '84	345	345	Provide Area Protection
IP&L PSI	Sunnyside / Gwynneville	70.8	44.0	Aug '84	345	345	Coordinated Agreement Deliver Generator Output

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Line Ownership List	Terminals	KM	MI	Planned Service Date	Nominal Voltage in kV		Remarks
					Oper	Dsgn	
<u>Public Service Co. of Indiana, Inc.</u>							
PSI	Gallagher / Gibson-Speed	32.2	20.0	Apr '84	345	345	Loop into Gallagher Provide Area Support
PSI	North / Columbus-Five Points	0.0	0.0	Apr '86	230	230	Loop into North Provide Area Support
PSI	Gwynneville / Connersville	45.0	28.0	Jan '87	345	345	Provide Area Support
PSI	Cayuga / Thorntown	80.5	50.0	Oct '89	230	230	Deliver Generator Output
PSI	Gibson / Dresser	144.9	90.0	Jun '80	345	345	Deliver Generator Output
PSI	Marble Hill / Speed	37.0	23.0	Aug '80	345	345	Convert 138 kV D/C to 1-138 kV & 1-345 kV Circuit Deliver Generator Output Provide Area Protection
PSI	Dresser / Cayuga	67.6	42.0	Sep '80	345	345	Provide Area Protection
PSI	Marble Hill / Madison	26.5	16.5	Mar '81	345	345	Convert 138 kV D/C to 1-138 kV & 1-345 kV Circuit Deliver Generator Output Provide Area Protection
PSI	Kokomo Webster St. / Greentown	32.2	20.0	Dec '81	230	230	Provide Area Support
PSI	Peru / Greentown	40.2	25.0	Dec '81	230	230	Provide Area Support
PSI	Marble Hill / Columbus	83.7	52.0	Mar '82	765	765	Deliver Generator Output
PSI	Gwynneville / New Castle	38.6	24.0	Apr '82	345	345	Provide Area Support
PSI	Columbus / Gwynneville	64.4	40.0	Jan '84	765	765	Provide Area Protection

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Line Ownership List	Terminals	KM	MI	Planned Service Date	Nominal Voltage In kV		Remarks
					Oper	Dsgn	
Northern Indiana Public Service Company							
NIPS	Luchtman Rd. / Mich. City-Babcock	0.0	0.0	Jun '87	345	345	
NIPS	Chicago Ave. / Dune Acres-Sheffield	0.0	0.0	Jun '80	345	345	
NIPS	Stillwell / Babcock-Dumont (AEP)	0.0	0.0	Jun '81	345	345	
NIPS	Munster / Lake George-Burnham (CE)	0.0	0.0	Jun '82	345	345	
NIPS	Schahfer / St. John	64.4	40.0	Jun '83	345	345	
NIPS	Dune Acres / Miller	19.3	12.0	Jun '84	345	345	
NIPS	Miller / Green Acres	14.4	9.0	Jun '84	345	345	
NIPS	Dune Acres / Lake George	30.5	19.0	Jun '86	345	345	
NIPS	New Site / Burr Oak	80.5	50.0	Jun '87	345	345	
NIPS	New Site / Schahfer	72.4	45.0	Jun '87	345	345	
NIPS	New Site / Reynolds	27.3	17.0	Jun '87	345	345	
NIPS	Leesburg / Lagrange	53.1	33.0	Jun '87	345	345	

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Line Ownership List	Terminals	KM	MI	Planned Service Date	Nominal Voltage In kV Oper Dsgn		Remarks
Hoosier Energy							
HED	Merom / Worthington	45.5	28.3	Sep '80	345	345	Deliver Generator Output
HED	Worthington / Bloomington	51.0	31.7	Sep '80	345	345	Deliver Generator Output Increase Interchange Capability
Indianapolis Power & Light Company							
IP&L	Columbus / Gwynneville	41.8	26.0	Apr '82	345	345	Coordinated Agreement
IP&L	Stout / Hanna-Thompson	1.6	1.0	Apr '84	345	345	Relieve Overloads
IP&L	Hanna / Prospect	8.0	5.0	Apr '88	345	345	Relieve Overloads
IP&L	Patriot / Sunnyside	173.8	108.0	Oct '88	345	345	Transmission for New Generation

Table 1F.15

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Indiana Region

	1977		1978		1979	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	9598	10336	10861	10753	11636	12197
2. Peak Demand	8340	8172	8359	8348	8654	7852
3. Planned Reserves (1-2)	1258	2164	2502	2405	2982	4345
4. Planned Reserves (%) (3/2)x100	15.1	26.5	29.9	28.8	34.5	55.3
5. Net Transactions (Imports-Exports)	709	1318	520	156	67	-505
6. Total Capability (1+5)	10307	11654	11381	10909	11703	11692
7. Total Reserves (6-2)	1967	3482	3022	2561	3049	3840
8. Total Reserves (%) (7/2)x100	23.6	42.6	36.2	30.7	35.2	48.9
9. Scheduled Maintenance	83	1032	427	555	586	1375
10. Capability after Maintenance (6-9)	10224	10622	10954	10354	11117	10317
11. Reserves after Maintenance (10-2)	1884	2450	2595	2006	2463	2465
12. Reserves after Maintenance (%) (11/2)x100	22.6	30.0	31.0	24.0	28.5	31.4
13. Inoperable Capability <u>1/</u>	0	0	0	0	0	0
14. Available Capability (10-13)	10224	10622	10954	10354	11117	10317
15. Available Reserves (14-2)	1884	2450	2595	2006	2463	2465
16. Available Reserves (%) (15/2)x100	22.6	30.0	31.0	24.0	28.5	31.4
17. Forced Outages	1626	1918	1955	1318	1673	1527
18. Actual Capability after Forced Outages (14-17)	8598	8704	8999	9036	9444	8790
19. Actual Reserves (18-2)	258	532	640	688	790	938
20. Actual Reserves (%) (19/2)x100	3.1	6.5	7.7	8.2	9.1	11.9

1/ Included in forced outages.

Table 1F.16

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Indiana Region

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability	11722	11893
2. Peak Demand	9315	9403
3. Planned Reserves (1-2)	2407	2490
4. Planned Reserves (%) (3/2)x100	25.8	26.5
5. Net Transactions (Imports-Exports)	203	158
6. Total Capability (1+5)	11925	12051
7. Total Reserves (6-2)	2610	2648
8. Total Reserves (%) (7/2)x100	28.0	28.2
9. Scheduled Maintenance <u>1/</u>	586	595
10. Capability after Maintenance (6-9)	11339	11456
11. Reserves after Maintenance (10-2)	2024	2053
12. Reserves after Maintenance (%) (11/2)x100	21.7	21.8
13. Inoperable Capability <u>2/</u>	0	0
14. Available Capability (10-13)	11339	11456
15. Available Reserves (14-2)	2024	2053
16. Available Reserves (%) (15/2)x100	21.7	21.8
17. Forced Outages <u>2/</u>	0	0
18. Actual Capability after Forced Outages (14-17)	11339	11456
19. Actual Reserves (18-2)	2024	2053
20. Actual Reserves (%) (19/2)x100	21.7	21.8

1/ 5% of total planned capability assumed by ERA,
from ECAR ERA-411 Report.

2/ Information not available.

Table 1F.17

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Indiana Region

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	11782	12478	12312	14607	14714	15848	15647	16322
2. Peak Demand	9742	9949	10160	10523	10636	11129	11099	11720
3. Planned Reserves (1-2)	2040	2529	2652	4048	4078	4719	4548	4602
4. Planned Reserves (%) (3/2)x100	20.9	25.4	26.1	38.5	38.3	42.4	41.0	39.3
5. Net Transactions (Imports-Exports)	598	319	307	407	410	502	505	619
6. Total Capability (1+5)	12380	12797	13119	14978	15124	16350	16152	16941
7. Total Reserves (6-2)	2638	2848	2959	4455	4488	5221	5053	5221
8. Total Reserves (%) (7/2)x100	27.1	28.6	29.1	42.3	42.2	46.9	45.5	44.5
9. Scheduled Maintenance <u>1/</u>	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	12380	12797	13119	14978	15124	16350	16152	16941
11. Reserves after Maintenance (10-2)	2638	2848	2959	4455	4488	5221	5053	5221
12. Reserves after Maintenance (%) (11/2)x100	27.1	28.6	29.1	42.3	42.2	46.9	45.5	44.5
13. Inoperable Capability <u>1/</u>	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	12380	12797	13119	14978	15124	16350	16152	16941
15. Available Reserves (14-2)	2638	2848	2959	4455	4488	5221	5053	5221
16. Available Reserves (%) (15/2)x100	27.1	28.6	29.1	42.3	42.2	46.9	45.5	44.5
17. Forced Outages <u>1/</u>	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	12380	12797	13119	14978	15124	16350	16152	16941
19. Actual Reserves (18-2)	2638	2840	2959	4455	4488	5221	5053	5221
20. Actual Reserves (%) (19/2)x100	27.1	28.6	29.1	42.3	42.2	46.9	45.5	44.5

1/ Information not available.

Table 1F.17.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Indiana Region

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	16474	16666	16474	16666	17118	17810	18118	18871	18679	19371
2. Peak Demand	11544	12370	12020	13036	12489	13603	12984	14436	13503	15189
3. Planned Reserves (1-2)	4930	4296	4454	3630	4529	4207	5134	4435	5176	4182
4. Planned Reserves (%) (3/2)x100	42.7	34.7	37.1	27.8	37.1	30.9	39.5	30.7	38.3	27.5
5. Net Transactions (Imports-Exports)	620	623	623	627	676	631	229	235	232	239
6. Total Capability (1+5)	17094	17289	17097	17293	17794	18441	18347	19106	18911	19610
7. Total Reserves (6-2)	5550	4919	5077	4257	5305	4838	5363	4670	5408	4421
8. Total Reserves (%) (7/2)x100	48.1	39.8	42.2	32.7	42.5	35.6	41.3	32.3	40.1	29.1
9. Scheduled Maintenance ^{1/}	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	17094	17289	17097	17293	17794	18441	18347	19106	18911	19610
11. Reserves after Maintenance (10-2)	5550	4919	5077	4257	5305	4838	5363	4670	5408	4421
12. Reserves after Maintenance (%) (11/2)x100	48.1	39.8	42.2	32.7	42.5	35.6	41.3	32.3	40.1	29.1
13. Inoperable Capability ^{1/}	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	17094	17289	17097	17293	17794	18441	18347	19106	18911	19610
15. Available Reserves (14-2)	5550	4919	5077	4257	5305	4838	5363	4670	5408	4421
16. Available Reserves (%) (15/2)x100	48.1	39.8	42.2	32.7	42.5	35.6	41.3	32.3	40.1	29.1
17. Forced Outages ^{1/}	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	17094	17289	17097	17293	17794	18441	18347	19106	18911	19610
19. Actual Reserves (18-2)	5550	4919	5077	4257	5305	4838	5363	4670	5408	4421
20. Actual Reserves (%) (19/2)x100	48.1	39.8	42.2	32.7	42.5	35.6	41.3	32.3	40.1	29.1

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^{1/} Information not available.

Table 1F.18.1

PLANNED NET CAPABILITY AS OF JANUARY 1, BY TYPE OF FUEL - MW
Indiana Region

S u m m e r _ C a p a b i l i t y

<u>Electric Region</u>	<u>Nuclear Steam</u>	<u>Coal Steam</u>	<u>Steam</u>	<u>Combust. Turbine</u>	<u>Internal Combust.</u>	<u>Steam</u>	<u>Combust. Turbine</u>	<u>I.C.</u>	<u>Convent.</u>	<u>Pumped Storage</u>	<u>Total Capability</u>
1980	-	10671	408	532	32	-	24	-	65	-	11732
% Total	-	91.0	3.5	4.5	0.3	-	0.2	-	0.5	-	100.0
1981	-	10671	408	532	32	-	24	-	65	-	11732
% Total	-	91.0	3.5	4.5	0.3	-	0.2	-	65	-	100.0
1982	-	11171	408	592	32	-	24	-	65	-	12292
% Total	-	91.0	3.3	4.8	0.3	-	0.2	-	0.5	-	100.0
1983	938	12291	408	622	32	-	24	-	65	-	14380
% Total	6.5	85.5	2.8	4.3	0.2	-	0.2	-	0.5	-	100.0
1984	938	12635	363	622	32	-	24	-	65	-	14679
% Total	6.4	86.1	2.5	4.2	0.2	-	0.2	-	0.4	-	100.0
1985	1876	13190	363	622	32	-	24	-	65	-	16172
% Total	11.6	81.6	2.2	3.8	0.2	-	0.2	-	0.4	-	100.0
1986	1876	13534	331	622	32	-	24	-	65	-	16484
% Total	11.4	82.1	2.0	3.8	0.2	-	24	-	65	-	100.0
1987	1876	14034	331	622	32	-	24	-	65	-	16984
% Total	11.0	82.6	2.0	3.7	0.2	-	0.1	-	0.4	-	100.0
1988	2520	14034	331	622	32	-	24	-	65	-	17628
% Total	13.5	80.7	1.8	3.4	0.2	-	0.1	-	0.3	-	100.0
1989	2520	15034	331	622	32	-	24	-	65	-	18628
% Total	13.5	80.7	1.8	3.4	0.2	-	0.1	-	0.3	-	100.0

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Table 1F.18.2

PLANNED NET CAPABILITY AS OF JANUARY 1, BY TYPE OF FUEL - MW
Indiana Region

W i n t e r C a p a b i l i t y

<u>Electric Region</u>	<u>Nuclear Steam</u>	<u>Coal Steam</u>	<u>Steam</u>	<u>Combust. Turbine</u>	<u>Internal Combust.</u>	<u>Steam</u>	<u>Combust. Turbine</u>	<u>I.C.</u>	<u>Convent.</u>	<u>Pumped Storage</u>	<u>Total Capability</u>
1980	-	10741	426	628	33	-	-	-	65	-	11893
% Total	-	90.3	3.6	5.3	0.3	-	-	-	0.5	-	100.0
1981	-	10741	426	628	33	-	-	-	65	-	11893
% Total	-	90.3	3.6	5.3	0.3	-	-	-	0.5	-	100.0
1982	-	11241	426	713	33	-	-	-	65	-	12478
% Total	-	90.1	3.4	5.7	0.3	-	-	-	0.5	-	100.0
1983	938	12366	476	743	33	-	-	-	65	-	14571
% Total	6.4	84.7	2.9	5.1	0.2	-	-	-	0.5	-	100.0
1984	938	12710	381	743	33	-	-	-	65	-	14870
% Total	6.3	85.5	2.6	5.0	0.2	-	-	-	0.4	-	100.0
1985	1876	13265	381	743	33	-	-	-	65	-	16363
% Total	11.5	81.1	2.3	4.5	0.2	-	-	-	0.4	-	100.0
1986	1876	13609	349	743	33	-	-	-	65	-	16675
% Total	11.2	81.6	2.1	4.5	0.2	-	-	-	0.4	-	100.0
1987	1876	14109	349	743	33	-	-	-	65	-	17175
% Total	10.9	82.2	2.0	4.3	0.2	-	-	-	0.4	-	100.0
1988	2520	14109	349	743	33	-	-	-	65	-	17819
% Total	14.1	79.2	1.9	4.2	0.2	-	-	-	0.4	-	100.0
1989	2520	15109	349	743	33	-	-	-	65	-	18819
% Total	13.4	80.3	1.9	3.9	0.2	-	-	-	0.3	-	100.0

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Table 1F.19

MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS AND (REMOVALS)
Indiana Region

System	Station	Unit Type	Fuel Type	Net Capability - MW		- Effective Date -	
				Summer	Winter	1980 ERA-411	1979 ERA-383
HED	Merom 2	ST	Coal	500	500	10/81	10/82
PSI	Gibson 5	ST	Coal	620	625	10/82	10/82
PSI	Marble Hill 1	PWR	UR	938	938	10/82	06/83
NIPS	R.M. Schahfer 17	ST	Coal	344	344	06/83	10/83
IP&L	Petersburg 4	ST	Coal	515	515	10/83	01/84
PSI	Marble Hill 2	PWR	UR	938	938	01/84	04/83
SIGE	A.B. Brown 2	ST	Coal	250	250	01/84	06/85
NIPS	R.M. Schahfer 18	ST	Coal	344	344	06/85	12/86
HED	Undesignated	ST	Coal	500	500	12/86	12/84
NIPS	Bailly N-1	BWR	UR	644	644	06/87	10/88
IP&L	Patriot 1	ST	Coal	650	650	10/87	01/88
NIPS	Unknown	ST	Coal	500	500	01/88	10/88
SIGE	A.B. Brown 3	ST	Coal	500	500	01/88	04/86
PSI	Undesignated	Unknown	Unknown	500	500	10/89	10/88 *

* 1130 MW given as capability

MICHIGAN ELECTRIC COORDINATED SYSTEMS (MECS) ELECTRIC REGION 18

Historical Perspective

Electric Region 18 (ER 18-MECS) consists of the electric systems in Lower Michigan, excluding the AEP subsidiary in the Southeast corner, and one system in the eastern corner of Upper Michigan. The following systems are included in the data of this section: Consumers Power Co.; Detroit Edison Co.; Edison Sault Electric Co; Lansing, Michigan Municipal; and the Michigan Municipal and Cooperative Pool.

All of the systems for which data are included in the following are regular or liaison members of the ECAR organization (East Central Area Reliability Coordination).

The Detroit Edison Company and Consumers Power Company are Michigan's two largest electric utility companies, serving about 90 percent of the state's population. In December 1962 the two companies entered into an Electric Power Pooling Agreement and subsequently formed the Michigan Electric Coordinated Systems (MECS) in 1973. The agreement provides for mutual assistance and coordination of the expansion of generating and major transmission facilities. Also, operation and maintenance of electric facilities are coordinated for economy as well as reliability of service. The Michigan Electric Power Coordination Center has been constructed at Ann Arbor, Michigan to facilitate the coordination of the generation and transmission facilities of the two companies. Coordination with Ontario Hydro is also conducted at the center as well as coordination with other regions.

The Michigan Municipal and Cooperative Pool (MMCP) initially was established in 1968, the current members are: Conalco (Consolidated Aluminum Co); Grand Haven, MI Municipal; Hart Hydro Electric; Lowell, MI Municipal; Northern Michigan Electric Cooperative; and Zeeland, MI Municipal. The objective of the pooling agreement is that the participants collectively shall provide capacity adequate to carry the total annual demands of all participants with adequate reserve capacity, through the coordination of their planning and construction of additional generating and transmission facilities. MMCP operates a control center for economic dispatch of generating units.

Shown below are the summer and winter peak demand of the MECS region for the period 1977-79:

TABLE 1 G.1
Historical Peak Demand* -MW
MECS Region

	<u>June</u>	<u>Summer</u> <u>July</u> <u>Aug.</u>	<u>Sept.</u>	<u>Dec.</u>	<u>Winter</u> <u>Jan</u>	<u>Feb</u>
1977	11570	<u>12634</u> 11336	11091	10992	<u>11140</u>	10887
1978	11777	12369 <u>12043</u>	<u>12626</u>	11250	<u>11433</u>	11141
1979	11533	11917 <u>11976</u>	11324	<u>10857</u>	10715	10495

Underline Indicates Seasonal Peak
*Non-Coincident

The Summer Peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August but occurred in September in 1978.

The winter peak usually occurs in January, but it may occur in any winter month, depending on the combination of weather and economic activity in the region and occurred in December in 1979.

The following table shows the scheduled maintenance performed each period and also the capability unavailable because of forced outages or otherwise inoperable.

TABLE 1 G.2
Scheduled Maintenance and Unavailable Capabilities
MECS Region

	Summer			Winter		
	<u>Scheduled</u> <u>Mainte-</u> <u>nance</u> <u>(MW)</u>	<u>Other</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Total</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Scheduled</u> <u>Mainte-</u> <u>nance</u> <u>(MW)</u>	<u>Other</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Total</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>
1977	401	1939	2340	1341	3626	4967
1978	790	3301	4091	431	2100	2531
1979	624	1644	2268	936	1922	2858

The capability unavailable for reasons other than scheduled maintenance varied from 10-20% of the installed capability in summer and from 12-22% in winter.

The reserve margins for the 1977-79 seasonal peak periods are shown below, considering the effects of scheduled maintenance and other outages.

TABLE 1 G.3
Historical Seasonal Reserves
MECS Region

<u>Peak Demand</u>	<u>Total capability</u>	<u>Total Reserves</u>	<u>Capability after maintenance</u>	<u>Available Reserves</u>	<u>Actual capability</u>	<u>Actual Reserves</u>
(MW)	(MW)	(%)	(MW)	(%)	(MW)	(%)
1977 12645	17480	38.2	17079	35.1	15140	19.7
1978 12652	18714	47.8	17924	41.7	14623	15.6
1979 12018	17745	47.7	17121	42.5	15477	28.8

Winter

1977 11157	18116	62.4	16775	50.4	13149	17.9
1978 11434	16623	45.4	16192	41.6	14092	23.2
1979 10872	17160	57.8	16224	49.2	14302	31.5

The reserve margins shown above indicate that for the 1977-79 period sufficient capability was available to meet the demand requirements in both the summer and winter periods.

Shown in Table 1 G.4 are the MECS regions energy requirements, summer and winter demands and annual load factors for the 1977-79 period.

TABLE 1 G.4

Historical Energy, Peaks and Load Factors
MECS Region

	<u>Energy Requirement</u> (GWH)Growth %)		<u>Summer Demand</u> (MW)(Growth-%)		<u>Winter Demand</u> (MW)(Growth-%)		<u>Annual Load Factor</u> (%)
1977	70075	-	12645	-	11157	-	63.3
1978	71700	2.3	12652	0.1	11434	2.5	64.7
1979	72010	0.4	12018	(5.0)	10872	(4.9)	68.4
%Growth 1977-79 1.4							

Over the period, the energy requirements grew at a compound growth rate of 1.4%, the summer demand declined 2.5% and the winter demand declined 1.3%. The low growth rate of the energy requirements reflects the depressed economic conditions of the area, which is greatly dependent on the auto industry. The demands decreased because of economic conditions, conservation effects, and milder winter conditions in 1979.

CURRENT PERSPECTIVE

The projected 1980 summer and winter non-coincident MECS region peak demands are shown on Table 1 G.5

TABLE 1 G.5

Projected 1980 Seasonal Peak Demand*-MW
MECS Region

<u>Summer</u>				<u>Winter</u>		
June	July	Aug	Sep	Dec	Jan	Feb
12136	12697	12261	11766	11356	11255	11071

*Non Coincident

The 1980 summer and winter demands are projected to occur in July and December, respectively, this is consistent with previous occurrences. However, the peak may occur in any month of the season depending on economic and climatic conditions.

The 1980 summer planned capability of the MECS region is estimated to be 16451 MW and the summer non-coincident peak demand is projected to be 12735 MW, resulting in planned reserves of 3716 MW or 29.2%. After adjustments for scheduled receipts and deliveries, total reserves decrease to 3131 MW or 24.6%.

In the ECAR ERA 411 report for the future 1980-1989 the Michigan Group companies do not list inoperable capability either for scheduled maintenance or possible forced outages. However, ECAR provides an indication of scheduled maintenance for the entire region.

The estimate prepared for the 411 report is based on the level of planned maintenance that is currently projected for the periods of heaviest load demand during the upcoming summer and winter season, i.e., five percent of total installed capability during the summer of 1980 and five percent of total installed capability during the winter of 1980/81.

The summer and winter reserve margins for the MECS elective region are shown below:

TABLE 1 G.6

1980 Reserves Margins *
MECS Region

Summer			Winter		
Planned Reserves	Total Reserves	Available** Reserves	Planned Reserves	Total Reserves	Available** Reserves
(MW) (%)	(MW) (%)	(MW) (%)	(MW) (%)	(MW) (%)	(MW) (%)
3716 29.2	3131 24.6	2309 18.1	6261 55.0	5683 49.9	4801 42.2

*Based on ERA Form 411

**5% of total installed capability assumed-from ECAR EPA form-411 report of scheduled outages.

The margins shown above have not been adjusted for forced outages of capacity, as the amount of these outages are unknown ahead of time. If these outages do not exceed the maximum outages of the 1977-79 periods 20% of planned capacity during summer period and 22% during the winter, the resultant actual deficit would be 981 MW (-7.7%) and 919 MW (-8.1%), respectively. In order to meet the deficit in the 1980 summer reserves, if it occurs, about 1000 MW will have to be imported from other regions. It is noted that it is common practice for the region to import large amounts of power.

During 1977-1979, from 1550 MW to 2600 were imported to increase the summer reserve situation.

The summer capability of the generating facilities planned in the MECS Region by January 1, 1980 is 16438 MW. The capability breakdown by fuel type is shown below.

TABLE 1G.7

Planned Summer Capability, January 1, 1980 -(MW)

Electric Region	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capa- bility
			ST	CT	IC	ST	CT	IC	Conv.	Pumped Conv. Storage	
	698	8807	3747	316	189	29	559	54	167	1872	16438
% of Total	4.3	53.6	22.8	1.9	1.1	0.2	3.4	0.3	1.0	11.4	100.0

About 53.6% of the current capability is coal-fired steam capacity; 22.8%, oil-fired steam; and 1.9% is oil-fired combustion turbine capacity. There is 698 MW 4.3% of nuclear capacity installed in the Electric Region. There is a 1872 MW pumped storage hydro-electric plant (Ludington) in the region which is a portion of the plant (624 MW) is currently contracted to the Commonwealth Edison Company in MAIN and is handled as an export in the data. There are no new units scheduled before September 1980. Thus, there is no effect on the summer 1980 reserve margin from possible delay in service of such units. The unit scheduled for September 1980 is a 791 MW coal unit. A delay of this unit beyond the beginning of the winter 1980 peak period could increase the winter 1980 actual deficit from an estimated -919 MW or -8.1% to 1710 MW or -15.0%. The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown below.

TABLE 1G.8

1980 Load Requirements
MECS Region

<u>Energy Requirement</u> (GWH)	<u>Summer Demand</u> (MW)	<u>Winter Demand</u> (MW)	<u>Annual L.F.</u> (%)
71300	12735	11384	63.7
%Growth 1980/79 (1.0)	6.0	4.7	

The 1980 projected summer and winter demands are projected to grow at considerably higher rates than they did during the 1977-79-period-(2.5%) and (1.3)%, respectively. However, the projected 1980 summer demand is (0.8)% less than the 1979 demand which had been decreased in 1979 (12840 MW) and the projected 1980 winter demand is (2.5)% less than that which had been projected for the 1979 winter season (11,678MW) the projected 1980 energy growth rate of (1.0)% over 1979 actual requirements reflects the depressed economic activity in the region, which is highly dependent on the auto industry.

Delays of future critical bulk power transmission facilities are required to be reported under Item 5-C of the ERA 411 report. In the April 1, 1980 FCAR report, no delays are reported for this Electric Region.

FUTURE PERSPECTIVE

The range of total reserves for the MECS region for the periods 1981-85 and 1986-89 are tabulated below.

Table 1G.9

Range of Total Reserves -%
MECS Region

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
26.4-38.0	45.2-60.0	20.8-34.3	44.4-56.2

The available reserves have been determined after deducting a nominal amount for scheduled maintenance (5% of the planned capability) from the reserve margin each period. No adjustments have been made for outages, as these are unknown. However, if the maximum outage rates of 20% and 22% which occurred during the summer and winter peak periods, respectively, are deducted

from the available reserves, reserve margins are sufficient in each winter period. However, negative reserves would occur in all years in the summer period, except for 1985 and 1986. Imports of 400 MW-1600 MW would be required if additional capacity is not installed. It should be noted that it is customary for the region to import large amounts of nonscheduled power. In 1977-1979, 1550-2600 MW of power were imported.

Shown below are the projected growth rates of demand and energy for each period and the overall rates for 1981-89.

TABLE 1G.10

Projected Energy and Demand Growth Rates
MECS Region

	Energy GWH	Requirements Growth %	Summer MW	Peak Demand Growth %	Winter MW	Peak Demand Growth %	Annual Load Factor
1981	73970	3.7	13161	3.3	11747	3.2	64.2
1982	76830	3.9	13627	3.4	12105	3.0	64.4
1983	79930	4.0	14199	4.0	12574	3.7	64.3
1984	82540	3.3	14652	3.1	12952	2.9	64.1
1985	85150	3.2	15162	3.4	13357	3.0	64.1
Growth 81-85		3.6		3.6		3.3	
1986	88030	3.4	15686	3.3	13773	3.0	64.1
1987	90650	3.0	16206	3.2	14154	2.7	63.8
1988	93690	3.3	16718	3.1	14620	3.2	63.8
1989	95920	2.4	17173	2.7	14940	2.1	63.8
Growth 86-89		2.9		3.1		2.8	

The 1981-1985 summer demands projected to grow at a compound rate of 3.6%; 1986-1989, 2.9%; and overall, 1981-1989, at 3.3%. The winter demands are projected to grow at a rate of 3.3% during the 1981-1985 period; 2.8% in the 1986-89 period; with an overall 1981-89 of 3.0%.

The summer demand growth rates for each time period is considerably greater than the 1977-79 rate of (7.5%, but is less than ECAR region as a whole, which is projected to have a 1981-1989 growth rate of 3.8%. The winter demands growth rates also are considerably greater than the 1977-79 rate of (1.3%), but less than the ECAR region rate of 3.9%.

If actual demands are lower than those which are projected to occur, the reserve margins will be increased from those indicated above.

The energy requirements are projected to grow at a rate of 3.6% from 1981-1985; 2.9% from 1986-89; and at an overall rate of 3.3% from 1981-1989. The overall growth rate is less than the projected growth rate of 3.8% for systems as a whole in ECAR.

During the 1981-85, period three nuclear units are scheduled to be placed in service Fermi #2-1093MW, Midland #1-522 MW, and Midland #2-505 MW. Two coal-fired units Belle River #1 and #2, 664 MW each are also scheduled for installation.

Only one unit is scheduled for installation after 1985 Frickson #2 a 150 MW coal-fired steam faculty. Palisades #1 a nuclear unit will be shutdown in August 1987 for 24 months for steam generator replacement.

It is important that in-service dates of major installaitons be met.

Under the conditions stated, with the historical 1977-1979, maximun forced outage rate of 20% of the summer installed capability and 22% of the winter capability, negative reserve margins will result in each year, except the winter of 1984, if the generating units planned are delayed beyond the peak period. This would require additonal non-scheduled power imports of 105-2244 M.W. As noted before, the region has historically depended on large power imports to maintain adequate reserves.

The summer and winter capability of units installed in the region during the period 1980-1989 is shown by type of fuel in table 1G.18. The percentages of each type of capacity for the target years 1980, 1984 and 1989 are given below.

TABLE 1 G.11
Planned Generating Capability By Type of Fuel - (%)
 MECS Region

Summer Capability

	Nuclear Steam	Coal Steam	Oil ST CT IC			Natural Gas ST CT IC			Hydro Conv. P.S.		Total Capability
1980	4.3	53.6	22.8	1.9	1.1	0.2	3.4	0.3	1.0	11.4	100.0
1984	9.6	51.9	20.9	1.7	1.0	0.5	3.0	0.4	0.9	10.1	100.0
1989	12.2	52.2	19.4	1.6	0.9	0.5	2.8	0.3	0.8	9.3	100.0

Currently, coal is the primary fuel for about 54% of the installed capability. Oil-fired capacity represents 26%, pumped storage 11%, nuclear 4%, natural gas 4% and conventional hydroelectric 1%. The only major change for the further 1989 target date is that nuclear capacity will rise to 12% all other fuel sources will decline slightly, since only nuclear and coal-fired capacity represent major additions.

An appraisal of anticipated transmission system performance in ECAR is prepared immediately prior to each summer and winter peak load period. Each member system participates in the appraisal procedure and the material which appears in the final ECAR report is normally limited to those items which are of particular significance to the overall region. The appraisal is based on careful analysis of various studies carried out by the ECAR Transmission System Performance Working Group under the direction of the Transmission System Performance Panel and by individual ECAR companies, either among themselves or jointly with systems adjacent to ECAR. Where the appraisal procedure indicates a potential contingency which could lead to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions where necessary. These reports are intended as a supplement to, and not a substitute for, internal studies by the individual systems in ECAR.

A wide range of postulated system conditions were considered during the course of the various studies referred to above but no localized transmission problems were apparent in the MECS region.

The most recent ECAR appraisal studies were for summer 1979 and winter 1979-80. These studies showed that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission systems within ECAR would be maintained at a high level.

Emergency Transfer Capabilities to adjacent regions, based on the NERC definition, were reported as follows:

TABLE 1 G.12

Emergency Transfer Capability-MW
MECS Region

<u>Transfer</u>	<u>Summer 1979 Capability</u>	<u>Winter 1979-80 Capability</u>
ECAR to MAAC	3300+	3300+
ECAR to NPCC (NYPP)	2200	2950
ECAR to MAIN	3450	3950
ECAR to SERC (TVA)	1800	1600
ECAR to SERC(VACAR)	1250	1900*
ECAR from MAAC	2450	3300+
ECAR from NPCC(NYPP)	3300+	2900
ECAR from MAIN	4000+	3800
ECAR from SERC (TVA)	2000	2100
ECAR from SERC(VACAR)	2700	2950*

*ETC Values determined with established operating procedures in effect.

All ECAR systems evaluate their individual network performance using the testing criteria presented in ECAR Document No.1. A listing of a representative number of the tests which were made to evaluate 1984 conditions accompanys this discussion. Based on an analysis of these studies, it has been concluded that the ECAR bulk power transmission network as now projected for the 1984 period is capable of withstanding the contingencies listed in ECAR Document No. 1 without suffering area-wide break-up and/or collapse of the network. This appraisal is based on the assumption that current financial and environmental problems will be resolved in a timely manner and that ECAR member systems will be able to provide the facilities shown. Should any of the EHV transmission facilities planned for the 1980-1984 period be delayed as a result of excessive lag in the certification process or as a result of difficulties in financing these projects due to inadequate rate relief, appropriate short term operating procedure will need to be developed in order to maintain, to the greatest extent possible, the reliability of electric power supply within ECAR. Such procedures, if invoked, may jeopardize the reliability of the power supply in the affected area.

TABLE 1 G.13
Summer 1984 Emergency Transfer Capability-MW
MECS Region

<u>Transfer</u>	<u>ETC MW</u>	<u>Transfer</u>	<u>ETC MW</u>
ECAR to MAAC	4350	ECAR from MAAC	2600
ECAR to NPCC (NYPP)	1950	ECAR from NPCC	2900
ECAR to MAIN	2900	ECAR from MAIN	4000+
ECAR to SERC (TVA)	2500	ECAR from SERC(TVA)	3200
ECAR to SERC(VACAR)	2250	ECAR from SERC(VACAR)	5500+

TABLE 1 G. 14
Historical Capability (MW) and Reserves (MW and Percent)
MECS Region

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	15236	16108	16126	15823	16192	16057
2. Peak Demand	12645	11157	12652	11434	12018	10872
3. Planned Reserves (1-2)	2591	4951	3474	4389	4174	5185
4. Planned Reserves (%) (3-2) x 100%	20.5	44.4	27.5	38.4	34.7	47.7
5. Net Transactions (Imports-Exports)	2244	2008	2588	800	1553	1103
6. Total Capability (1+5)	17480	18116	18714	16623	17745	17160
7. Total Reserves (6-2)	4835	6959	6062	5189	5727	6288
8. Total Reserves (%) (7-2) x 100%	38.2	62.4	47.8	45.4	47.7	57.8
9. Scheduled Maintenance	401	1341	790	431	624	936
10. Capability after Maintenance (6-9)	17079	16775	17924	16192	17121	16224
11. Reserves after Maintenance (10-2)	4434	5618	5272	4758	5103	5352
12. Reserves after Maintenance (%) (11-2) x 100%	35.1	50.4	41.7	41.6	42.5	49.2
13. Inoperable Capability Included in 17	0	0	0	0	0	0
14. Available Capability (10-13)	17079	16775	17924	16192	17121	16224
15. Available Reserves (%) (14-2)	4434	5618	5272	4758	5103	5352
16. Available Reserves (%) (15-2) x 100%	35.1	50.4	41.7	41.6	42.5	49.2
17. Forced Outages	1939	3626	3301	2100	1644	1922
18. Actual Capability after Forced Outages (14-17)	15140	13149	14623	14092	15477	14302
19. Actual Reserves (18-2)	2495	1992	1971	2658	3459	3430
20. Actual Reserves (%) (19-2) x 100%	19.7	17.9	15.6	23.2	28.8	31.5

XI.1.145

TABLE 1G. 15
Current Capability (MW) and Reserves (MW and Percent)

		<u>MECS REGION</u>	
		1980	
		<u>Summer</u>	<u>Winter</u>
1. Planned Capability		16451	17645
2. Peak Demand		12735	11384
3. Planned Reserves (1-2)		3716	6261
4. Planned Reserves (%) $(3\frac{0}{2}) \times 100\%$		29.2	55.0
5. Net Transactions (Imports-Exports)		-585	-585
6. Total capability (1+5)		15966	17067
7. Total Reserves (6-2)		3131	5683
8. Total Reserves (%) $(7\frac{0}{2}) \times 100\%$		24.6	49.9
9. Scheduled Maintenance <u>1/</u>		822	822
10. Capability after Maintenance (6-9)		15044	16185
11. Reserves after Maintenance (10-2)		2308	4801
12. Reserves after Maintenance (%) $(11\frac{0}{2}) \times 100\%$		18.1	42.2
13. Inoperable Capability		0	0
14. Available Capability (10-13)		15044	16185
15. Available Reserves (14-2)		2309	4801
16. Available Reserves (%) $(15\frac{0}{2}) \times 100\%$		18.1	42.2
17. Forced Outages		0	0
18. Actual Capability After Forced Outage (14-17)		15044	16185
19. Actual Reserves (18-2)		2309	4801
20. Actual Reserves (%) $(19\frac{0}{2}) \times 100\%$		18.1	42.2

1/ 5% of total planned capability assumed by ERA-From ECAR ERA 411 report.

TABLE 1G. 16.1

Future Capability (MW) And Reserves (MW and Percent)
MECS Region

	<u>1981</u>		<u>1982</u>		<u>1983</u>		<u>1984</u>		<u>1985</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	17242	17645	18333	18738	18582	18985	19246	20456	21198	21642
2. Peak Demand	13161	11747	13627	12105	14199	12574	14652	12952	15162	13357
3. Planned Reserves (1-2)	4081	5898	4706	6633	4383	6411	4594	7504	6036	8285
4. Planned Reserves (%) (3-2) x 100%	31.0	50.2	34.5	54.8	30.9	51.0	31.4	57.9	39.8	62.0
5. Net Transactions (Imports-Exports)	-602	-583	-604	-601	-607	-292	-300	-296	-279	-276
6. Total Capability (1+5)	16640	17062	17731	18137	17975	18693	18946	20160	20919	21366
7. Total Reserves (6-2)	3479	5315	4104	6032	3776	6119	4294	7208	5757	8009
8. Total Reserves (%) (7-2) x 100%	26.4	45.2	30.1	49.8	26.6	48.7	29.3	55.7	38.0	60.0
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	16640	17062	17731	18137	17975	18693	18946	20160	20919	21366
11. Reserves after Maintenance (10-2)	3479	5315	4104	6032	3776	6119	4294	7208	5757	8009
12. Reserves after Maintenance (%) (11-2) x 100%	26.4	45.2	30.1	49.8	26.6	48.7	29.3	55.7	38.0	60.0
13. Inoperable Capability 1/	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	16640	17062	17731	18137	17975	18693	18946	20160	20919	21366
15. Available Reserves (14-2)	3479	5315	4104	6032	3776	6119	4294	7208	5757	8009
16. Available Reserves (%) (15-2) x 100%	26.4	45.2	30.1	49.8	26.6	48.7	29.3	55.7	38.0	60.0
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	16640	17062	17731	18137	17975	18693	18946	20160	20919	21366
19. Actual Reserves (18-2)	3479	5315	4104	6032	3776	6119	4294	7208	5757	8009
20. Actual Reserves (%) (19-2) x 100%	26.4	45.2	30.1	49.8	26.6	48.7	29.3	55.7	38.0	60.0

1/ Information not available.

TABLE 1G. 16.2

Future Capability (MW) and Reserves (MW and Percent)

	<u>MECS Region</u>							
	<u>1986</u>		<u>1987</u>		<u>1988</u>		<u>1989</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	21348	21792	21348	21052	20723	21052	20713	21792
2. Peak Demand	15686	18773	16206	14154	16718	14602	17173	14940
3. Planned Reserves (1-2)	5662	8019	5142	6898	4005	6450	3540	6852
4. Planned Reserves (%) $(3\frac{1}{2}) \times 100\%$	36.1	58.2	31.7	48.7	24.9	44.2	20.6	45.9
5. Net Transactions (Imports-Exports)	-280	-276	-281	-277	-281	35	30	34
6. Total Capability (1+5)	21068	21516	21067	20775	20442	21087	20743	21826
7. Total Reserves (6-2)	5382	7743	4861	6621	3724	6485	3570	6886
8. Total Reserves (%) $(7\frac{1}{2}) \times 100\%$	34.3	56.2	30.0	46.8	22.3	44.4	20.8	46.1
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	21068	21516	21067	20775	20442	21087	20743	21826
11. Reserves after Maintenance (10-2)	5382	7743	4861	6621	3724	6485	3570	6886
12. Reserves after Maintenance (%) $(11\frac{1}{2}) \times 100\%$	34.3	56.2	30.0	46.8	22.3	44.4	20.8	46.1
13. Inoperable Capability 1/	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	21068	21516	21067	20775	20442	21087	20743	21826
15. Available Reserves (14-2)	5382	7743	4861	6621	3724	6485	3570	6886
16. Available Reserves (%) $(15\frac{1}{2}) \times 100\%$	34.3	56.2	30.0	46.8	22.3	44.4	20.8	46.1
17. Forced Outages 1/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	21068	21516	21067	20775	20442	21087	20743	21826
19. Actual Reserves (18-2)	5382	7743	4861	6621	3724	6485	3570	6886
20. Actual Reserves (%) $(19\frac{1}{2}) \times 100\%$	34.3	56.2	30.0	46.8	22.3	44.4	20.8	46.1

1/ Information not available.

TABLE 1G. 17.1
Installed Net capability as of January 1, By type of Fuel -MW
MECS Region
Summer Capability

Electric Region 18-MECS	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Comb. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convent.	Pumped Storage	
1980	698	8807	3747	316	189	29	559	54	167	1872	16438
% Total	4.3	53.6	22.8	1.9	1.1	0.2	3.4	0.3	1.0	11.4	100.0
1981	698	9598	3747	316	187	29	559	60	167	1872	17233
% Total	4.0	55.7	21.7	1.8	1.1	0.2	3.2	0.4	1.0	10.9	100.0
1982	698	9598	3747	316	187	29	559	60	167	1872	17233
% Total	4.0	55.7	21.7	1.8	1.1	0.2	3.2	0.4	1.0	10.9	100.0
1983	1791	9598	3747	316	187	29	559	66	167	1872	18332
% Total	9.8	52.4	20.4	1.7	1.0	0.2	3.0	0.4	0.9	10.2	100.0
1984	1791	9648	3878	316	187	95	559	66	167	1872	18579
% Total	9.6	51.9	20.9	1.7	1.0	0.5	3.0	0.4	0.9	10.1	100.0
1985	2574	10312	3878	316	187	95	559	66	167	1872	20026
% Total	12.8	51.8	19.4	1.6	0.9	0.5	2.8	0.3	0.8	9.4	100.0
1986	3079	10312	3878	316	187	95	559	66	167	1872	20531
% Total	15.0	50.2	18.9	1.6	0.9	0.5	2.7	0.3	0.8	9.1	100.0
1987	3079	10462	3878	316	187	95	559	66	167	1872	20681
% Total	14.9	50.6	18.8	1.5	0.9	0.5	2.7	0.3	0.8	9.0	100.0
1988	2444	10462	3878	316	187	95	559	66	167	1872	20046
% Total	12.2	52.2	19.4	1.6	0.9	0.5	2.8	0.3	0.8	9.3	100.0
1989	2444	10462	38378	316	187	95	559	66	167	1872	20046
% Total	12.2	52.2	19.4	1.6	0.9	0.5	2.8	0.3	0.8	9.3	100.0

TABLE 1G. 17.2
Installed Net capability as of January 1, By type of Fuel -MW
MECS Region
Winter Capability

Electric Region 18-MECS	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			Steam	Comb. Turbine	Internal Combust.	Steam	Comb Turb.	I.C.	Convent.	Pumped Storage	
1980	803	8830	3769	408	190	29	736	54	168	1872	16859
% Total	4.8	52.4	22.3	2.4	1.1	0.2	4.4	0.3	1.0	1.1	100.1
1981	803	9621	3769	408	188	29	736	60	168	1872	17654
% Total	4.6	54.5	21.3	2.3	1.1	0.2	4.2	0.3	0.9	10.6	100.0
1982	803	9621	3769	408	188	29	736	60	168	1872	17654
% Total	4.6	54.5	21.3	2.3	1.1	0.2	4.2	0.3	0.9	10.6	100.0
1983	1896	9621	3769	408	188	29	736	60	168	1872	18753
% Total	10.1	51.3	20.1	2.2	1.0	0.2	3.9	0.3	0.9	10.0	100.0
1984	1896	9671	3300	408	188	95	736	66	168	1872	19000
% Total	10.1	50.9	20.5	2.1	1.0	0.5	3.9	0.3	0.9	9.8	100.0
1985	2703	10335	3900	408	188	95	736	66	168	1872	20471
% Total	13.2	50.5	19.1	2.0	0.9	0.5	3.6	0.3	0.8	9.1	100.0
1986	3225	10335	3900	408	188	95	736	66	168	1872	20993
% Total	15.4	49.2	18.6	1.9	0.9	0.5	3.5	0.3	0.8	8.9	100.0
1987	3225	10485	3900	408	188	95	736	66	168	1872	21143
% Total	15.2	49.6	18.4	1.9	0.9	0.5	3.5	0.3	0.8	8.9	100.0
1988	2485	10485	3900	408	188	95	736	66	168	1872	20403
% Total	12.2	51.4	19.1	2.0	0.9	0.5	3.6	0.3	0.8	9.2	100.0
1989	2485	10485	3900	408	188	95	736	66	168	1872	20403
% Total	12.2	51.4	19.1	2.0	0.9	0.5	3.6	0.3	0.8	9.2	100.0

SECTION XI.2

ELECTRIC RELIABILITY COUNCIL OF TEXAS

(ERCOT)

ELECTRIC RELIABILITY COUNCIL OF TEXAS

Introduction

The members of the Electric Reliability Council of Texas (ERCOT) supply electric power within the State of Texas only and do not operate in synchronism with any of the other nine Electric Reliability Council areas. The entire ERCOT area is included in the Texas Interconnected Systems Group (TIS) (Electric Region 23). The area internally is divided into the North and South Texas areas for planning and operating purposes, and each area is monitored by a security center. There are eight control centers in the South Texas area and four in the North Texas area.

ERCOT usually experiences its peak electric load in July or August during periods of prolonged hot dry weather. Its winter peak occurs in December or January and is approximately 75 percent of the summer peak load.

During the year 1978, ERCOT obtained 78.9 percent of its electric generation from natural gas, 18.6 percent from coal and lignite, 2.3 percent from fuel oil and 0.2 percent from hydro.

The existing high voltage transmission system is at the 345 kV level and extends east to west in the North Texas portion of the area and north to south between North and South Texas areas. The 345 kV system between North and South Texas was constructed primarily for reliability and until recently was not used for economy energy transactions.

Texas is presently isolated electrically from other Electric Regions in the nation. The Central & South West Corporation (CSW) has petitioned the Federal Energy Regulatory Commission to order ERCOT to interconnect with the Southwest Power Pool Reliability Council. As a result of this petition, systems in ERCOT and SPP are currently involved in a joint voluntary study to test the feasibility of such a connection. Transmission lines proposed by CSW were shown on the transmission map furnished with ERCOT's 1980 ERA-411 report, but were not included in the list of bulk power line additions nor were they used in the load flow and stability studies furnished in the report. Consumation of this interconnection would have some effect on the load and supply situation in future years.

TEXAS INTERCONNECTED SYSTEMS GROUP (REGION 23)

Historical Perspective

Historically, the Texas Interconnected Systems (TIS) area has been a high growth area with an annual compound rate of growth of approximately 10 percent for both peak demand and energy during the period 1950 through 1976. During the early years of this period, electric usage increased rapidly due to low electric rates, which were attributable to an abundance of low cost natural gas. However, as a result of the decline in natural gas reserves, other fuel related problems and the general effects of inflation, the annual growth rate of electric usage has been declining as shown in the following table:

Table 2 A.1

COMPOUND ANNUAL GROWTH RATE
Texas Interconnected Systems Group

Period	Compound Annual Growth Rate	
	Peak Demand	Annual Energy
	(%)	(%)
1950-60	12.9	11.8
1960-70	10.1	10.5
1970-76	6.4	6.3

Table 2A.3 tabulates the actual summer and winter peak demands and the annual net energy for load for the years 1977 through 1979. The annual growth rates of demand and energy for 1977 to 1978 and 1978 to 1979 and the annual load factors are also tabulated.

The TIS area's peak demand occurs in the summer months during periods of prolonged hot dry weather, and therefore, is extremely temperature sensitive. As shown on Table 2A.3 the 1979 summer peak demand was 0.7 percent less than the 1978 summer peak demand.

Although not shown on Table 2A.3, the summer energy requirements in 1979 were 3 percent lower than 1978. This reduction in both peak and energy was attributed to three factors listed in order of importance: (1) lower than normal temperatures during the summer of 1979; (2) implementation of the President's 78 degree Fahrenheit temperature rule; and (3) customer conservation.

The following table shows the actual mid-1978 summer generating capability by fuel type and the resulting 1978 actual energy production:

Table 2A.2

GENERATING CAPABILITY & ENERGY GENERATION (1978)
Texas Interconnected Systems Group

Capacity Type	Fuel Type	Capability (Summer)		Annual Generation	
		(MW)	(% of Total)	(GWh)	(% of Total)
Steam	Gas	31,105	79.79	111,581	75.74
Steam	Oil	0	0.0	3,354	2.27
Steam	Coal	6,046	15.51	27,342	18.56
Hydro	Water	230	0.59	288	0.19
Gas Turbine	Gas	1,363	3.50	721	0.50
Gas Turbine	Oil	58	0.15	37	0.03
Combined Cycle	Gas	182	0.46	3,982	2.70
Combined Cycle	Oil	0	0.0	8	0.01
Total		38,984	100.00	147,313	100.00

As shown above, the TIS area is still heavily dependent on natural gas for the production of energy. During 1978, the TIS area burned 1,172 million Mcf of natural gas (84 percent of which was under firm contract) and only 5.6 million barrels of oil. Residual oil represented 79 percent of the oil burned, and the remainder was distillate. A total of 22 million tons of coal was consumed with the majority, 86 percent, being supplied from utility owned intrastate lignite mines. There are presently no nuclear-fueled generating units in service in the TIS area although five units are scheduled for operation during the 1980's.

The bulk power system planning criteria for TIS states that sufficient generating capacity will be provided, as nearly as practicable, to insure total reserves of at least 15 percent of the forecasted maximum hour demand of the Interconnected System. The TIS Planning Subcommittee is presently conducting a reserve study to determine if the 15 percent criteria should be increased. Historically, the total reserves of TIS have been much greater than 15 percent. The operating reserve policy of TIS is for both the North Texas and the South Texas group of companies to each maintain spinning reserve equal to the sum of the capability of the largest unit in operation plus 100 MW. Tables 2A.4.1 and 2A.4.2 give the actual reserve

situations that occurred in the TIS area for 1977 through 1979 for each of the three summer months (June, July and August) and the three winter months (December, January and February). In 1979 the largest generating units in both the North and South Texas sub-areas were 750 MW for a total spinning reserve requirement of 1,700 MW. Operating reserves exceeded this amount (1700 MW) in each of the historical periods listed. Total reserves varied from a high of 102.7 percent of demand in December of 1977 to a low of 31.6 percent in July of 1978.

Transmission in TIS is normally constructed on a service territory basis and most of the 345 kV backbone lines were built to serve new generating capacity and for reliability. At the end of 1979, there were approximately 3,900 miles of lines in operation. As the coal-oil cost spread increases, so does economy energy exchanges. TIS has adopted Transmission Facilities Services Policy Guidelines to assist in arrangements for wheeling and the use of transmission facilities on other systems.

Table 2A.3

HISTORICAL PEAK DEMAND AND ENERGY GROWTH
Texas Interconnected Systems Group (Region 23)

	D e m a n d				Annual Energy Requirements		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1977	26,894	-	20,203	-	136,743	-	58.0
1978	28,645	6.51	21,521	6.52	147,608	7.95	58.8
1979	28,455	-0.66	22,052	2.47	150,231	1.78	60.3

Current Perspective

Table 2A.5 gives the current projected generating capability and reserves for the summer of 1980 and the 1980/81 winter peak period for the Texas Interconnected Systems Group (TIS). As stated earlier, the summer peak demand for TIS is extremely temperature sensitive and as such can occur during either of four summer months, June, July, August or September, although it usually occurs in July or August. In the TIS region, the lowest demands of the year occur on the system in the winter (December 1 through the end of February for this report) with the peak hour demands remaining fairly flat during this period.

The systems in TIS are planning to install 1,670 MW of coal-fired generating capacity before the 1980 summer peak period as stated in their ERA-411 report. They also plan to add a 545 MW lignite unit and reactivate a 30 MW gas unit before the winter peak. According to up-to-date information, no delays in these schedules are anticipated.

Total reserves are projected to be 34.5 percent during the summer of 1980 and 83.2 percent in the winter. Available reserves, considering capability reductions due to scheduled maintenance and inoperable capability, are expected to be 32.3 percent and 38.7 percent for the summer and winter peak, respectively. Actual reserves of 20.5 percent and 23.9 percent for summer and winter are estimated by the ERA staff based on historical forced outages averaged for the period 1977 through 1979. All reserve amounts are well above the TIS reserve criteria.

The total summer planned capability of 42,379 MW includes almost 23 percent of coal-fired generation and over 76 percent of natural gas capacity (see Table 2A.9). This compares to a coal-gas mix of 16 and 80 percent, respectively, in 1978.

During 1980, and before the summer peaking season, TIS plans to place eleven 345-kV circuits totaling 277 miles in service. The primary purpose of most of these transmission additions is to provide a path for generator output, although several are needed for overload relief on the system or to serve increased loads. Two are being constructed to increase interchange capability, one to provide area support and one for stability requirements.

The TIS Group (Region 23) should experience no capacity problems during the 1980 summer and 1980/81 winter peak periods.

Future Perspective

During the 1981-1984 period, TIS plans to install 3,550 MW of nuclear-fueled capacity and 2,253 MW of coal and lignite-fired capacity. This additional capacity is being installed to serve a projected annual load growth of 5.2 percent between the summer of 1980 and the summer of 1984.

As shown on Table 2A.6, the summer total reserves for TIS varies from a low of 22.6 percent in 1984 to a high of 33.8 percent in 1981. Winter total reserves are much higher than the summer since this is the low load period for TIS, varying from 68.7 percent in 1984 to 79.4 percent in 1981. These total reserve figures are well above the TIS reserve criteria. Available reserves, which includes the effects of scheduled maintenance and inoperable capability, are also well above the TIS total reserve criteria (15%) with the lowest available reserve of 21.7 percent occurring in the summer of 1984. Actual reserves, which includes the effect of forced outages estimated by ERA, are expected to range between 8.5 percent during the winter of 1983 and 22.8 percent during the winter of 1981.

If nuclear delays (projected by the Nuclear Regulatory Commission) and possible delays in coal units (assumed possible by ERA) are also considered, the resulting actual reserves would range between 4.3 percent in the winter of 1983 and 18.2 percent during the winter of 1981. Table 2A.10 provides a list of scheduled nuclear units and includes the NRC projected in-service dates. The ERA staff assumed that the 400 MW Gibbons Creek Unit No. 1 (Lignite) could possibly be delayed beyond the 1982 summer peak period since construction is less than 50 percent complete.

During the 1981-1984 period, TIS expects to construct approximately 1,753 miles of 345-kV transmission circuits. Although about one-half of these circuits are being constructed to transmit power from existing and scheduled generating units, a large number are also needed for overload relief, stability requirements, and increased interchange capability.

TIS appears to have an excellent reserve posture during the 1981 through 1984 period. This is due, to a great extent, to its program for phasing down the use of natural gas as a boiler fuel as evidenced by the number of scheduled coal-fired units listed in Table 2A.11.

Available reserves, including only the effect of inoperable capability, for the five year period 1985-1989 are shown on Table 2A.7. The projected reserves are approximately 20 percent during the summer peak periods and 58 percent during the winter. An NRC projected delay in the in-service date of the 1,130 MW Allens Creek nuclear unit starting in the winter of 1987 and extending beyond the winter of 1989 reduces reserve margins to approximately 54 percent during the winter and 19 percent during the summer for these years.

TIS is planning to install 1,380 MW of nuclear capacity, 10,940 MW of coal and lignite capacity and retire a total of 1,673 MW of gas-fired capacity between the summer of 1985 and the summer of 1989. The summer peak demand is estimated to increase by 8,417 MW during the same period.

There are approximately 1,220 miles of 345-kV transmission circuits planned in service during the 1985-1989 period. The purpose of these lines is about evenly divided between generator output, overload relief or load growth, and stability requirements. In addition, several lines are planned for increased interchange capability, area support, and voltage relief.

The Texas Interconnected Systems Group (Region 23) appears to have excellent reserves throughout the 10-year period covered in this report.

The growth in summer and winter peak demand and annual energy as reported in the 1980 ERA-411 are shown on Table 2A.8. TIS is projecting an average annual growth for the summer peak demand and annual energy of 5 percent and a 5.2 percent growth for the winter peak during the 10-year report period. The annual load factor as projected is approximately 58 percent and remains nearly constant throughout the period.

Based on the projected planned capability shown on Tables 2A.5, 2A.6, and 2A.7, annual energy requirements can be met throughout the 10-year period assuming a stable fuel supply. For example, the average annual plant factor in 1989 based on the total installed capability is approximately 48 percent. If natural gas and oil capability were reduced by one-half in 1989 due to a shortage of these fuels, the remaining fuels would be required to make up the difference, which in effect would mean that the average annual plant factor must be increased to about 64 percent.

Table 2A.4.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Texas Interconnected Systems Group (Region 23)

	- S U M M E R -								
	1977/78			1978/79			1979/80		
	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.
1. Planned Capability	35273	35188	35565	37621	37649	38569	40847	40847	40827
2. Peak Demand	24664	26327	26894	27280	28645	28177	27943	28455	28429
3. Planned Reserves (1-2)	10609	8861	867	10341	9004	10392	12904	12392	12398
4. Planned Reserves (%) (3/2)x100	43.0	33.7	32.2	37.9	31.4	36.9	46.2	43.5	43.6
5. Net Transactions (Imports-Exports)	120	18	-24	136	35	-111	250	236	399
6. Total Capability (1+5)	35393	36206	35541	37757	37684	38458	41097	41083	41226
7. Total Reserves (6-2)	10729	8879	8647	10477	9039	10281	13154	12628	12797
8. Total Reserves (%) (7/2)x100	43.5	33.7	32.2	38.4	31.6	36.5	47.1	44.4	45.0
9. Scheduled Maintenance	2037	344	224	1763	797	1588	2859	1201	1770
10. Capability after Maintenance (6-9)	33356	34862	35317	35994	36887	36870	38238	39882	39456
11. Reserves after Maintenance (10-2)	8692	8535	8423	8714	8242	8693	10295	11427	11027
12. Reserves after Maintenance (%) (11/2)x100	35.2	32.4	31.3	31.9	28.8	30.9	36.8	40.2	38.8
13. Inoperable Capability	1328	1678	2406	1173	2010	1263	1413	1894	2032
14. Available Capability (10-13)	32028	33184	32911	34821	34877	35607	36825	37988	37424
15. Available Reserves (14-2)	7364	6857	6017	7541	6232	7430	8882	9533	8995
16. Available Reserves (%) (15/2)x100	29.9	26.0	22.4	27.6	21.8	26.4	31.8	33.5	31.6
17. Forced Outages	1252	1668	1821	2596	2024	2095	3311	961	1446
18. Actual Capability after Forced Outages (14-17)	30776	31516	31090	32225	32853	33512	33514	37027	35978
19. Actual Reserves (18-2)	6112	5189	4196	4945	4208	5335	5571	8572	7549
20. Actual Reserves (%) (19/2)x100	24.8	19.7	15.6	18.1	14.7	18.9	19.9	30.1	26.6

Table 2A.4.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Texas Interconnected Systems Group (Region 23)

	- W I N T E R -								
	1977/78			1978/79			1979/80		
	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.
1. Planned Capability	36282	36833	36818	38839	39479	39478	40833	40777	40177
2. Peak Demand	17950	20203	19733	20817	21521	20904	21782	22052	21749
3. Planned Reserves (1-2)	18332	16630	17085	18022	17958	18574	19051	18725	18428
4. Planned Reserves (%) (3/2)x100	102.1	82.3	86.6	86.6	83.4	88.9	87.5	84.9	84.7
5. Net Transactions (Imports-Exports)	94	189	301	519	297	73	-65	164	-50
6. Total Capability (1+5)	36376	37022	37119	39358	39776	39551	40768	40941	40127
7. Total Reserves (6-2)	18426	16819	17386	18541	18255	18647	18986	18889	18378
8. Total Reserves (%) (7/2)x100	102.7	83.3	88.1	89.1	84.8	89.2	87.2	85.7	84.5
9. Scheduled Maintenance	6719	6459	6009	8237	5871	5908	7717	6509	6032
10. Capability after Maintenance (6-9)	29657	30563	31110	31121	33905	33643	33051	34432	34095
11. Reserves after Maintenance (10-2)	11707	10360	11377	10304	12384	12739	11269	12380	12346
12. Reserves after Maintenance (%) (11/2)x100	65.2	51.3	57.7	49.5	57.5	60.9	51.7	56.1	56.8
13. Inoperable Capability	2342	3088	2365	2085	4039	3451	2915	3411	3006
14. Available Capability (10-13)	27315	27475	28745	29036	29866	30192	30136	31021	31089
15. Available Reserves (14-2)	9365	7272	9012	8219	8345	9288	8354	8969	9340
16. Available Reserves (%) (15/2)x100	52.2	36.0	45.7	39.5	38.8	44.4	38.4	40.7	42.9
17. Forced Outages	2689	2376	2453	1802	2950	1859	1472	2240	2483
18. Actual Capability after Forced Outages (14-17)	24626	25099	26292	27234	26916	28333	28664	28781	28606
19. Actual Reserves (18-2)	6675	4896	6559	6417	5395	7429	6882	6729	6857
20. Actual Reserves (%) (19/2)x100	37.2	24.2	33.2	30.8	25.1	35.5	31.6	30.5	31.5

Table 2A.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Texas Interconnected Systems Group (Region 23)

	<u>1980 Summer Peak</u>	<u>1980/81 Winter Peak</u>
1. Planned Capability <u>1/</u>	42379	42832
2. Peak Demand	31621	23456
3. Planned Reserves (1-2)	10758	19376
4. Planned Reserves (%) (3/2)x100	34.0	82.6
5. Net Transactions (Imports - Exports)	145	145
6. Total Capability (1+5)	42524	42977
7. Total Reserves (6-2)	10903	19521
8. Total Reserves (%) (7/2)x100	34.5	83.2
9. Scheduled Maintenance	305	8059
10. Capability after Maintenance (6-9)	42219	34918
11. Reserves after Maintenance (10-2)	10598	11462
12. Reserves after Maintenance (%) (11/2)x100	33.5	48.9
13. Inoperable Capability	383	2379
14. Available Capability (10-13)	41836	32539
15. Available Reserves (14-2)	10215	9083
16. Available Reserves (%) (15/2)x100	32.3	38.7
17. Forced Outages <u>2/</u>	3727	3485
18. Actual Capability after Forced Outages (14-17)	38109	29054
19. Actual Reserves (18-2)	6488	5598
20. Actual Reserves (%) (19/2)x100	20.5	23.9

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ Estimated by ERA staff based on historical forced outage amounts.

Table 2A.6

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Texas Interconnected Systems Group (Region 23)

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	44012	43927	44327	45455	45995	45742	46992	48014
2. Peak Demand	33306	24795	35089	26014	36873	27386	38796	28802
3. Planned Reserves (1-2)	10706	19132	9238	19441	9122	18356	8196	19212
4. Planned Reserves (%) (3/2)x100	32.1	77.2	26.3	74.7	24.7	67.0	21.1	66.7
5. Net Transactions (Imports-Exports)	550	550	550	550	604	604	575	575
6. Total Capability (1+5)	44562	44477	44877	46005	46599	46346	47567	48589
7. Total Reserves (6-2)	11256	19682	9788	19991	9726	18960	8771	19787
8. Total Reserves (%) (7/2)x100	33.8	79.4	27.9	76.8	26.4	69.2	22.6	68.7
9. Scheduled Maintenance	305	7824	160	8728	160	9776	160	9431
10. Capability after Maintenance (6-9)	44257	36653	44717	37277	46439	36570	47407	39158
11. Reserves after Maintenance (10-2)	10951	11858	9628	11263	9566	9184	8611	10356
12. Reserves after Maintenance (%) (11/2)x100	32.9	47.8	27.4	43.3	25.9	33.5	22.2	36.0
13. Inoperable Capability	1326	2466	176	2270	176	1278	176	2065
14. Available Capability (10-13)	42931	34187	44541	35007	46263	35292	47231	37093
15. Available Reserves (14-2)	9625	9392	9452	8993	9390	7906	8435	8291
16. Available Reserves (%) (15/2)x100	28.9	37.9	26.9	34.6	25.5	28.9	21.7	28.8
17. Forced Outages ^{1/}	3000	3730	4380	4230	4610	5570	4860	5135
18. Actual Capability after Forced Outages (14-17)	39931	30457	40161	30777	41653	29722	42371	31958
19. Actual Reserves (18-2)	6625	5662	5072	4763	4780	2336	3575	3156
20. Actual Reserves (%) (19/2)x100	19.9	22.8	14.5	18.3	13.0	8.5	9.2	11.0

XI.2.11

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	1150	1150	1150	1150	1150	1150	1150	0
22. Actual Capability (18-21)	38781	29307	39011	29627	40503	28572	41221	31958
23. Actual Reserves with Nuclear Delays (22-2)	5475	4512	3922	3613	3630	1186	2425	3156
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	16.4	18.2	11.2	13.9	9.8	4.3	6.3	11.0

^{1/} Estimated by ERA staff based on historical forced outage amounts.

Table 2A.7

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Texas Interconnected Systems Group (Region 23)

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	48486	48688	50638	51231	52617	55232	46925	57918	59433	60215
2. Peak Demand	40744	30028	42735	31827	44779	33389	46925	35079	49161	36881
3. Planned Reserves (1-2)	7742	18660	7903	19404	7838	21843	9598	22839	10272	23334
4. Planned Reserves (%) (3/2)x100	19.0	62.1	18.5	61.0	17.5	65.4	20.5	65.1	20.9	63.3
5. Net Transactions (Imports-Exports)	703	703	680	680	665	665	665	665	665	665
6. Total Capability (1+5)	49189	49391	51318	51911	53282	55897	57188	58583	60098	60880
7. Total Reserves (6-2)	8445	19363	8583	20084	8503	22508	10263	23504	10937	23999
8. Total Reserves (%) (7/2)x100	20.7	64.5	20.1	63.1	19.0	67.4	21.9	67.0	22.2	65.1
9. Scheduled Maintenance	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	49189	49391	51318	51911	53282	55897	57,188	58,583	60098	60880
11. Reserves after Maintenance (10-2)	8445	19363	8583	20084	8503	22508	10263	23504	10937	23999
12. Reserves after Maintenance (%) (11/2)x100	20.7	64.5	20.1	63.1	19.0	67.4	21.9	67.0	22.2	65.1
13. Inoperable Capability	176	1842	176	2265	156	3491	156	3200	156	2518
14. Available Capability (10-13)	49013	47549	51142	49646	53126	52406	57032	55383	59942	58362
15. Available Reserves (14-2)	8269	17521	8407	17819	8347	19017	10107	20394	10781	21481
16. Available Reserves (%) (15/2)x100	20.3	58.3	19.7	56.0	18.6	57.0	21.5	57.9	21.9	58.2
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	49013	47549	51142	49646	53126	52406	57032	55383	59942	58362
19. Actual Reserves (18-2)	8269	17521	8407	17819	8347	19017	10107	20304	10781	21481
20. Actual Reserves (%) (19/2)x100	20.3	58.3	19.7	56.0	18.6	57.0	21.5	57.9	21.9	58.2

XI.2.12

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	0	1130	1130	1130	1130	1130
22. Actual Capability (18-21)	49013	47549	51142	49646	53126	51276	5902	54253	58812	57232
23. Actual Reserves with Nuclear Delays (22-2)	8269	17521	8407	17819	8347	17887	8977	19174	9651	20351
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	20.3	58.3	19.7	56.0	18.6	53.6	19.1	54.7	19.6	55.2

1/ Estimated by ERA staff based on historical forced outage amounts.

Table 2A.8

FUTURE LOAD GROWTH
Texas Interconnected Systems Group (Region 23)

	<u>- D e m a n d -</u>				<u>Energy Requirements</u>		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	31621	-	23456	-	161000	-	58.0
1981	33306	5.3	24795	5.7	170100	5.7	58.3
1982	35089	5.4	26014	4.9	179300	5.4	58.3
1983	36873	5.1	27386	5.3	188600	5.2	58.4
1984	38796	5.2	28802	5.2	198100	5.0	58.1
1985	40744	5.0	30028	4.3	207900	4.9	58.2
1986	42735	4.9	31827	6.0	217900	4.8	58.2
1987	44779	4.8	33389	4.9	227600	4.5	58.0
1988	46925	4.8	35079	5.1	238600	4.8	57.9
1989	49161	4.8	36881	5.1	250000	4.8	58.1
1980-89		5.0		5.2		5.0	

Table 2A.9

Summer 1980, 1985, 1989, Generation Mix By Fuel Type
TEXAS INTERCONNECTED SYSTEMS GROUP (REGION 23)

<u>Type Fuel</u>	<u>Summer 1980</u>		<u>Summer 1985</u>		<u>Summer 1989</u>	
	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)
Nuclear	0	-	3,550	7.3	5,930	10.0
Coal	9,677	22.8	13,175	27.2	23,415	39.4
Gas	32,375	76.4	31,434	64.8	29,761	50.1
Oil	97	0.2	97	0.2	97	0.1
Hydro	230	0.6	230	0.5	230	0.4
Total	42,379	100.0	48,486	100.0	59,433	100.0

Table 2A.10

Projected Nuclear Generating Units for the Period 1980-1989
As Reported April 1, 1980 to the Department of Energy

Texas Interconnected Systems Group (Region 23)

Unit Name	Capability (MW)	In-Service Date As Reported April		NRC In-Service Date
		1979	1980	
Comanche Peak No. 1	1,150 <u>1/</u>	1-81	8-81	8-82
Comanche Peak No. 2	1,150 <u>1/</u>	1-83	1-83	8-84
South Texas Project No. 1	1,250 <u>2/</u>	4-82	2-84	3-84
South Texas Project No. 2	1,250 <u>2/</u>	4-83	2-86	3-86
Allens Creek No. 1	1,130 <u>3/</u>	6-85	11-87	Beyond 1989

1/ Joint ownership: Texas Utilities Company Systems (90%) and Texas Municipal Power Pool (10%).

2/ Joint ownership: Houston Lighting & Power Co. (30.8%), City of San Antonio (28%), Central Power & Light Company (25.2%), and City of Austin (16%).

3/ Owned by Houston Lighting & Power Company.

Table 2A. 11

Projected Coal-fired Generating Units for the Period 1980-1989
As Reported April 1, 1980, to the Department of Energy

Texas Interconnected Systems Group (Region 23)

Unit Name	Capability (MW)	In-Service Date As Reported April		Company
		1980	1979	
Coletto Creek No. 1	550	3-80	12-79	Central Power & Light Co.
F.P.P. No. 2	550 <u>1/</u>	6-80	6-79	Lower Colorado River Authority
W.A. Parrish No. 7	570	6-80	6-80	Houston Lighting & Power Co.
Sandow No. 4	545	1-81	1-81	Texas Power & Light Co.
Gibbons Creek No. 1	400	6-82	6-82	Texas Municipal Power Pool
W.A. Parrish No. 8	540	5-83	12-82	Houston Lighting & Power Co.
Martin Lake No. 4	750 <u>2/</u>	2-85	1-85	Texas Utilities Co.
Twin Oaks No. 1	563	2-85	1-84	Texas Power & Light Co.
Limestone No. 1	700	4-85	4-85	Houston Lighting & Power Co.
Twin Oaks No. 2	563	2-86	1-86	Texas Power & Light Co.
Limestone No. 2	700	4-86	4-86	Houston Lighting & Power Co.
Oklunion No. 1	640 <u>3/</u>	1-87	1-87	West Texas Utilities Co.
Forest Grove No. 1	750 <u>2/</u>	1-87	1-84	Texas Utilities Co.
Undetermined	700	3-87	4-86	Houston Lighting & Power Co.
F.P.P. No. 3	400	6-87	4-86	Lower Colorado River Authority
Unassigned	750 <u>2/</u>	1-88	1-87	Texas Utilities Co.
Unassigned	600 <u>2/</u>	1-88	1-88	Texas Utilities Co.
Unassigned	600 <u>2/</u>	1-88	1-88	Texas Utilities Co.
Undetermined	700	3-88	-	Houston Lighting & Power Co.
Unassigned	400	6-88	6-87	Texas Municipal Power Pool
Unassigned	600 <u>2/</u>	1-89	-	Texas Utilities Co.
Unassigned	600 <u>2/</u>	1-89	-	Texas Utilities Co.
Unassigned	600 <u>2/</u>	1-89	-	Texas Utilities Co.
Unassigned	500	4-89	-	San Antonio Public Service Board
Undetermined	700	4-89	-	Houston Lighting & Power Co.

1/ Joint ownership: Lower Colorado River Authority (275 MW) and City of Austin (275 MW).

2/ Joint ownership: Texas Power & Light Company (33 1/3 percent), Texas Electric Service Company (33 1/3 percent), and Dallas Power & Light Company (33 1/3 percent).

3/ Joint ownership: West Texas Utilities Company (307 MW), Central Power & Light Company (135 MW), Southwestern Electric Power Company (148 MW) (Region 22), and Public Service Company of Oklahoma (50 MW) (Region 22).

SECTION XI.3
MID-ATLANTIC AREA COUNCIL
(MAAC)

Pennsylvania-New Jersey-Maryland Interconnection Region (PJM)Electric Region 5Historical

The Mid-Atlantic Area Council (MAAC) region is synonymous with the Pennsylvania-New Jersey-Maryland Interconnection (PJM) operating group; thus, there are no sub-regional groups. PJM has the distinction of being the oldest inter-connected group in continuous operation in the United States. There are eleven privately-owned utility operating companies and several municipal systems and electric cooperatives associated with the group.

The PJM operations are coordinated from a single operating center with each company's resources and loads committed as a single operating entity covering the States of New Jersey (97%), Maryland (60%), Delaware (100%), Pennsylvania (75%), and Washington, D.C. (100%). While this represents only 1.4% of the total United States area, it includes 9.3% of the total population.

The region includes a substantial area of the densely populated Northeast corridor and, as such, has considerable residential and commercial loads within several of the member companies. This is particularly true of the Potomac Electric Power Co., which serves Washington, D.C., and has no industrial load. Several other large cities are located in the region, including the Camden/Philadelphia area, Newark, New Jersey, and Baltimore, Maryland. There are some large industrial complexes, such as the oil refineries in New Jersey. As a result of heavy air conditioning loads, this is a summer peaking system, and presently, the winter peak is equal to about 90% of the summer peak.

The geographic location of this region is such that it is the bridge between the coal-burning utilities of the West and the imported oil-dependent utilities of the Northeast. It has a good mix of coal and oil generating capability with a somewhat higher base coal capability than base oil. However, oil fuel for this region is primarily imported from the Mid-East and, therefore, there is a constant pressure to reduce the use of oil as much as possible. Table 3A.1 indicates percentages of generation by fuel types for the years 1977 through 1979 and the percent of capability by fuel type for 1979.

Table 3A.1

Actual 1979 Capability and 1977-1979 Generating
Capacity by Fuel Type
Pennsylvania-New Jersey-Maryland Interconnection Region

PJM Plant Output *
Percentage of Total

<u>Year</u>	<u>Nuclear</u>	<u>Hydro</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
1977	20	3	49	28	1/
1978	22	2	46	30	0
1979	20	2	55	21	2

Plant Capability * 2/

Percentage of Total

1979	16	5	32	46	1
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* Based on EIA Form 4 data.

1/ Less than 1%

2/ Includes pumped storage.

Note: For the purposes of these comparisons, the pump storage output figures have been deleted as they generally require fossil fuel input for hydro output.

Slow growth in peak demands and increased oil conservation efforts have increased the demand for base load coal-fired generation and decreased the demand for oil and gas. As such, oil generation has been reduced in a manner that is not necessarily in proportion to the coal output increase. It is interesting to note that after the second oil embargo, there was a decided shift away from oil generation, with a small increase in gas usage. The drop in nuclear use experienced in 1979 is a direct result of the Three Mile Island incident.

XI.3.3

The traditional load growth enjoyed prior to the first oil embargo was sharply reduced in 1977 with still another growth reduction experienced after the 1978 shortage which resulted from conservation efforts. Actual figures, as obtained from ERA Forms 119 and 411, are shown in Table 3A.2 together with percentage of growth.

Table 3A.2

Actual Annual Net Energy, Peak Demands,, and Load Factors
Pennsylvania-New Jersey-Maryland Interconnection Region

Year	G W H	<u>Net Energy</u>	<u>Summer Peak</u>		<u>Winter Peak</u>		Load Factor
		<u>Percent</u>	<u>Percent</u>		<u>Percent</u>		
		<u>Change</u>	<u>M W</u>	<u>Change</u>	<u>M W</u>	<u>Change</u>	
1977	163,377		32,180		27,967		58
1978	169,036	3.5	31,686	-2.0	28,529	2.0	61
1979	171,810	1.6	31,654	-0.1	27,967	(2.0)	62
Growth 1977-79		2.6		-1.1		0	

While the average annual growth over the 3-year actual period is 2.6% for load and a negative 1% for peak, this cannot be used to extrapolate future growth with any degree of reliability. Also, as a result of comparatively mild weather, the load factor is somewhat above normal.

Table 3A.3 shows a breakdown of the actual 1978 generation by fuel type for comparative purposes. The summer plant capability is also indicated in the table.

Table 3A.3

Planned Capability and Generation by Prime Mover
Pennsylvania-New Jersey-Maryland Interconnection Region

PJM Capability and Generation by Prime Mover and Fuel Type - 1978

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>Summer 1980 Capability</u>	
		<u>MW</u>	<u>%</u>
Steam	Nuclear	7,076	15.8
Steam	Coal	15,510	34.7
Steam	Oil	11,980	26.7
Steam	Gas	0	0
Hydro	-	956	2.1
Pump Storage	-	1,280	2.9
Gas Turbine & Diesel	Oil	7,239	16.2
Gas Turbine	Gas	254	0.6
Combine Cycle	Oil	460	1.0
Combine Cycle	Gas	0	0
Other		0	0
Total,		44,755	100.0

To meet these generation requirements, fuel consumption was:

31.9 million tons of coal.
 9.0 million barrels of distillable oil.
 79.0 million barrels of residual oil.
 9.4 million MCF of natural gas.

Since the Federal Energy Regulatory Commission (FERC) gave only a temporary exemption to the prohibition of gas use by the utilities until the spring of 1980, future use of this fuel for electric generating purposes is in doubt until a new ruling is provided.

There are at present eight nuclear units in the region and eight more under construction. The future of Three Mile Island No. 2 remains in doubt at this time with, at best, an unknown return date for the unit. Three Mile Island Unit No. 1 could be available for service almost immediately, but projected NRC hearings indicate that this unit will be out of service for most of 1980.

The PJM system had adequate reserves to meet the load during the 1977-1979 peak periods with planned reserves varying between 37% and 41% for the summer and up to 59% in the winter. After considering net sales and purchases and capacity out of service, actual reserves were reduced to 9% to 20% for summer and 7% to 26% for winter. While the reserve criteria as dictated by the PJM Agreement approximates 22%, Table 3A.4 indicates actual reserves by months for the 3-year period.

Table 3A.4
Actual Reserve Margins in Percent
Pennsylvania-New Jersey-Maryland Interconnection Region

<u>Year</u>	<u>Planned Reserves</u>	<u>Available Reserves</u>	<u>Actual Reserves</u>
<u>Summer</u>			
1977	37.0	27.2	8.8
1978	38.1	25.7	19.7
1979	40.9	34.6	14.0
<u>Winter</u>			
1977	58.1	43.9	19.6
1978	56.5	38.9	25.8
1979	59.1	36.2	6.6

The reserve policy for MAAC states that the operating reserve is generating capability and equivalent generation in excess of forecast system peak load which is available within thirty minutes or less to provide primarily for adequate tie-line regulation in the event of load variations due to equipment failure and, under certain conditions, area protection. The operating reserve is divided into primary and secondary reserves, as follows:

1. Primary Reserve is that amount of generating capability or equivalent generation in excess of system load which is synchronized to the system or on standby and ready for immediate startup, and which is capable of being loaded within ten minutes or less to provide for adequate tie-line regulation in the event of load variations or equipment failure. The Primary Reserve is subdivided into Spinning Reserve and Quick-Start Reserve.

a. Spinning Reserve is that portion of Primary Reserve synchronized to the system.

b. Quick-Start Reserve is any remaining portion of Primary Reserve, adjusted by a factor to allow for the probability of failure of equipment to start. The pumping load of pumped storage hydro plants, when counted as Primary Reserve, is considered to fall within this category.

2. Secondary Reserve is that generating capability or equivalent generation in excess of system load which is either synchronized to the system or on standby and ready for startup, and which is capable of being loaded within from ten to thirty minutes of the occurrence of a contingency.

In addition, there are load reduction programs to meet emergencies in the event of insufficient operating reserve. Table 3A.5 indicates the reduction procedures and the estimated load reduction:

Table 3A.5

Emergency Curtailment Procedures
Pennsylvania-New Jersey-Maryland Interconnection Region

<u>Procedure</u>	<u>Estimated Peak Load Reduction</u>
1. Curtailment of nonessential power company station light and power load	75 MW
2. Voltage reduction of 3%	425 MW
Voltage reduction of 5%	500 MW
3. Curtailment of nonessential load in power company buildings	25 MW
4. Voluntary customer load curtailment as required up to a maximum of -- Summer	1,400 MW
-- Winter	600 MW
5. Radio and television load curtailment appeal	Dependent upon public response
6. Manual load dumping.	As required, up to 10,000 MW on a procedural basis

The need for load reduction procedures is assessed for the interconnection as a whole by the PJM Interconnection Dispatcher, who then notifies the PJM member systems of the total requirement and their share. In the absence of constraining local conditions, each member system initiates the specified procedure to reduce load in an amount equal to its prearranged share of the interconnection requirement.

In addition to these manual procedures, underfrequency relays are installed to shed load automatically in the event of a power shortage which has caused system frequency to decay. Approximately 30% of the inter-connection load can be shed in this manner:

<u>Frequency</u>	<u>Minimum Load Dumped</u>
59.3 Hz	10%
58.9 Hz	10%
58.5 Hz	10%

The underfrequency relays are sufficiently distributed throughout PJM so that if any major area becomes isolated with generation deficiency and experiences declining frequency, 10% of that area's load will automatically be shed at each frequency listed above.

The system companies also have a number of interruptible load contracts with fourteen customers. The total load that can be interrupted is 206 MW from industrial accounts with a normal aggregate load of 250 MW. Table 3A.6 shows the additional detail.

Table 3A.6

Interruptible Load Contracts *
Pennsylvania-New Jersey-Maryland Interconnection Region

	<u>DEPL</u>	<u>GPU</u>	<u>PSEG</u>	<u>TOTAL</u>
No. of Customers	3	1	10	14
Total Load (KW)	119.4	17.0	113.7	250.1
Interrupt Load (KW)	98.5	10.0	93.5	206.0
Max. Time (Hrs./IR)	-	150	150	-
Max. Freq. (Time/IR)	-	20	15	-
Lead Time (Mins.)	30	15	120	-
Reaction Time (Mins.)	30	15	120	-
Vehicle for Interruption	Phone	Phone	Phone	-
Cause of Interruption	High Demand	High Demand	High Demand	-

* Based on 1978 ERA study.

The geographic situation of PJM puts it into an ideal location for wheeling of energy for the purposes of fuel conservation. This was more than adequately demonstrated when, during the coal strike, oil-fueled generation was moved from East to West (from the oil-fired plants of New England and New York to the coaldependent utilities of the West). More recently, the reverse has been proven in the coal-by-wire oil conservation transfers of energy West to East. The transmission is basically strong in both the East and West portions of the system. There are approximately 1,263 circuit miles of 500 KV lines, 160 circuit miles of 345 KV lines, and 4,400 circuit miles of 230 KV lines. Included are 53 inter-system connection points and 27 interpool connection points with New York Power Pool, The Cleveland Electric Illuminating Co., Allegheny Power System and Virginia Electric Power Company. At present, East-West intra-regional energy transfers are somewhat constrained due to construction slippage of the Hossensack-Elroy 500 KV line and the 500 KV loop around Washington, D.C. The delays in completion of these lines are primarily regulatory oriented with particular problems resulting from state commissions in the area of environmental impacts.

Current

The anticipated 1980 summer peak demand for the PJM System is 33,550 MW and is expected to occur in August. This would be an increase of 5.6% over the previous summer and is a reversal of the decreasing trend the area has been experiencing for the past two years, and only 4.3% above the previous highest peak of 32,180 MW in 1977. The winter peak is expected to be 29,850 MW, an increase of 6.7% over 1978. Total net energy for 1980 is anticipated at 177,848 GWH which is 3.5% above 1979--a somewhat larger increase than experienced in the previous year. The annual load factor on the summer peak would then be 60%. The 1980 planned winter capability to meet the load is 48,809 MW; and the summer capability is 44,755 MW. Table 3A.7 indicates the loads, resources and reserves for the 1980 summer and winter peaks.

Table 3A.7

1980 Reserve Margins *
Pennsylvania-New Jersey-Maryland Interconnection Region

	<u>Summer</u>	<u>Winter</u>
Planned Capability - MW	44,755	48,809
Peak Demand - MW	33.550	29,850
Planned Reserve - %	33.4	63.5
Net Transaction -MW	157	157
Total Reserves - MW	11,362	19,116
Total Reserves - %	33.9	64.0
Available Reserve - MW	10,034	14,285
Available Reserve - %	29.9	47.9

* Based on ERA 411 Report

As indicated in Table 3A.7 for the year 1980, the region will have adequate reserves well above the PJM Agreement criterion of 22 percent. The reserves indicated in Table 3A.7 do not include forced outages which generally run 15 percent daily, but are now at about 17 percent, due to the Three Mile Island outage. Thus, including the Three Mile Island outage in the available reserves, would adjust these figures downward to the 27.8 percent and 45.9 percent respectively.

To meet the system requirements of 177,848 GWH, it is expected that the region's plants will consume approximately 35 million tons of coal, 8 million barrels of distillate oil, 63 million barrels of residual oil and 10 million MCF natural gas.

The transmission system for 1980 is adequate for scheduled energy transfers, but has little reserve capacity for economy transfers without adversely affecting the reliability for emergency interchange. Among the constraints are the Hoosensack-Elroy 500 KV line, for which regulatory approval to begin construction was granted in December 1979. The line was originally scheduled for service in 1974; however, with a 12- to 16-month construction time, it will not be ready for service until the summer of 1981. When completed, it will be a third West-East 500 KV transmission path and will increase the capability of Eastern MAAC to import power. Another critical line under construction is the 500 KV Baltimore-Washington Loop. The absence of these two lines reduces the GAP ability of the system to transfer coal by wire to the Northeast.

The Three Mile Island Plant outage (which is considered a forced outage for the purpose of this report) is creating a voltage problem in Central Pennsylvania; and until Salem #2 Nuclear Plant comes on line in October 1980, there will also be a voltage problem in Eastern PJM.

In addition to the 500 KV lines under construction, approximately 180 miles of 230 KV transmission lines are scheduled for installation during 1980. These lines are primarily for local area protection and increased load-carrying capacity.

Future

Forecasts for the 1981-1989 time frame include a summer peak load growth of 2.6% per year average. However, for the first five years of the period, the anticipated peak growth is projected at 2.8%. During the same 9-year period, the energy requirements are expected to grow by approximately 3.2%. Detailed tables of the period load and capability growth are included in Tables 3A.14.1 and 3A.14.2. Table 3A.8 outlines the projected energy and peak demand growth during this period.

Table 3A.8

Projected Energy and Peak Demand
Pennsylvania-New Jersey-Maryland Interconnection Region

	<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	<u>GWh</u>	<u>Growth %</u>	<u>MW</u>	<u>Growth %</u>	<u>MW</u>	<u>Growth %</u>	<u>%</u>
1981	184476	3.7	34550	2.9	30980	3.8	61.0
1982	191391	3.7	35610	3.0	32000	3.3	61.4
1983	197578	3.2	36590	2.7	33080	3.4	61.7
1984	204058	3.3	37000	2.7	34230	3.5	62.0
1985	210729	3.3	38600	2.6	35370	3.2	62.4
Growth 81-85		3.4		2.8		3.4	
1986	217542	3.2	39600	2.6	36530	3.2	62.8
1987	223997	3.0	40550	2.4	37560	2.8	63.1
1988	230362	2.8	41440	2.2	38610	2.8	63.5
1989	236938	2.9	42370	2.2	39670	2.7	63.9
Growth 86-89		2.9		2.3		2.8	
Growth 81=89		3.2		2.6		3.1	

Table 3A.9

Projected Reserves *
Pennsylvania-New Jersey-Maryland Interconnections Region

	<u>Year</u>	<u>Planned Reserves</u>	<u>Total Reserves</u>	<u>Available Reserves</u>
Summer	1981	33.2	33.5	28.7
	1982	32.8	33.1	28.4
	1983	32.3	32.6	28.0
	1984	30.5	30.8	26.3
	1985	32.2	32.5	31.1
	1986	32.2	32.5	31.1
	1987	35.3	35.6	33.6
	1988	34.3	34.6	32.6
	1989	33.5	33.7	31.8
Winter	1981	56.8	57.2	41.6
	1982	55.8	56.2	40.7
	1983	54.2	54.5	39.4
	1984	51.0	51.3	36.5
	1985	52.1	52.4	50.9
	1986	50.5	50.8	49.4
	1987	52.9	53.2	51.0
	1988	50.9	51.1	49.0
	1989	49.0	49.3	47.2

* Based on ERA Form 411.

These reserves do not include forced outages and are somewhat larger than the PJM Agreement criteria, but are based on timely completion of all new equipment. Historically, this has not been the situation; and to reinforce this premise, unit slip-pages are outlined later in this report.

To meet the projected increases, approximately 13,100 MW of new base load generating capacity is planned, of which about 8,900 MW will be nuclear and 4,200 MW coal-fired. The nuclear additions will increase its proportional share of energy output from 20% in 1979 to about 28% in 1989. By 1989, the capacity breakdown would be 28% nuclear, 35% coal and 33% oil.

Table 3A.10 indicates the fuel percentages for each capacity type for the years 1984 and 1989, at the time of the summer peak.

Table 3A.10

Summer Capacity by Fuel Type
Pennsylvania-New Jersey-Maryland Interconnection Region

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>1984</u> <u>% of</u> <u>Total</u>	<u>1989</u> <u>% of</u> <u>Total</u>
Steam	Nuclear	20.7	27.7
Steam	Coal	33.6	35.2
Steam	Oil	25.1	20.2
Steam	Gas	-	-
Hydro	-	2.0	1.9
Pumped Storage	-	2.6	2.3
Gas Turbine	Oil	14.6	11.5
Gas Turbine	Gas	0.5	0.4
Combined Cycle	Oil	0.9	0.8
Combined Cycle	Gas	-	-
Other			

Table 3A.11 shows the major nuclear and coal units planned or under construction for the region. Shown in the table is the slippage experienced for each of the units, indicating the probability of a reduction in reserves should the forecast materialize as predicted.

Table 3A.11

Major Future Generating Unit In-Service Dates
Pennsylvania-New Jersey-Maryland Interconnection Region

<u>Utility</u>	<u>Plant Name</u>	<u>Name Plate Capacity</u> MW	<u>Original In-Service Date</u>	<u>In-Service Date as of April 1979</u>	<u>Present In-Service Date *</u>
<u>N U C L E A R</u>					
PSEG	Salem #2	1115	Mar 73	Aug 79	Oct 80
PEPL	Susquehanna #1	1152	Jan 79	Feb 81	Jan 82
PEPL	Susquehanna #2	1152	May 81	May 82	Jan 83
PSEG	Hope Creek #1	1067	Dec 82	Sep 84	Sep 84 ^{1/}
PSEG	Hope Creek #2	1067	Dec 82	May 86	May 86 ^{2/}
JECF	Fork River #1	1251	Nov 78	Dec 83	Dec 86 ^{3/}
PHEC	Limerick #1	1055	Aug 78	May 85	May 85
PHEC	Limerick #2	1055	Mar 80	May 87	May 87
<u>O I L</u>					
POEP	Chalk Pt #4	600	Dec 81	1982	Dec 81
<u>C O A L</u>					
DEPL	Indian River #4	446	May 79	Sep 80	Sep 80
BAGE	Brandon Shores #1	625	Jan 81	Jan 82	May 84
BAGE	Brandon Shores #2	625	May 85	Jan 84	Jan 88

Major PJM Plants - Planned Additions*

----- N U C L E A R -----

- N o n e -

----- O I L -----

- N o n e -

----- C O A L -----

			4/			
POEP	Dickerson #1	800	Mar 82	1987	May 87	
PEEC	Seward #7	625	May 84	Dec 85	May 87	
PEEC	COHO #1	625	May 86	May 8	May 89	
DEPL	Vienna #9	500	May 87	May 87	May 87	

* Based on Form ERA-119

- 1/ ERA all-service date 5/85
 2/ ERA all-service date 5/87
 3/ ERA all-service date 5/86
 4/ Only 400 MW reported; 400 MW uncommitted.

PJM companies indicate that some additional construction slippage is foreseen from the schedules prepared for this report. These are shown on Table 3A.11.

The most critical additional transmission line for the near term period is the 500 KV loop around the Washington, D.C., metropolitan area. Completion of this line has been delayed until 1983 due to regulatory problems. When completed, the line will improve stability in the Baltimore/Washington area and increase MAAC transfer capability with the adjacent ECAR and VACAR regions. By 1984, the inter-regional emergency net transfer capabilities from adjacent NPCC, ECAR, and SERC (VACAR) regions are anticipated as follows:

NPCC to MAAC: 2,250 MW
 ECAR to MAAC: 4,850 MW
 VACAR to MAAC: 4,850 MW

Note: Net transfers are incremental over base scheduled transfers or incremental over owned generation outside a company's boundary.

XI.3.16

Planned, under construction, or committed transmission lines for the future are:

<u>KV</u>	<u>Miles</u> <u>(1979-1983)</u>	<u>Miles</u> <u>(1984-1988)</u>
230	789	496
345	16	17
500	376	83

Total existing and planned as of December 31, 1988:

<u>KV</u>	<u>Miles</u>
230	5,580
345	193
500	1,722

[Based on NERC 9th Annual Review.]

Scheduled imports for the 1980 through 1989 period include 50 MW from APS (through 1980) and 107 MW from PASNY. There are no scheduled exports.

Table 3A.12

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent).
PJM Region

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	44084	44212	43748	44660	44613	44499
2. Peak Demand	32180	27967	31686	28529	31654	27967
3. Planned Reserves (1-2)	11904	16245	12062	16131	12959	16532
4. Planned Reserves (%) (3/2)x100	37.0	58.1	38.1	56.5	40.9	59.1
5. Net Transactions (Imports-Exports)	50	50	180	180	180	180
6. Total Capability (1+5)	44134	44262	43928	44840	44793	44679
7. Total Reserves (6-2)	11954	16295	12242	16311	13139	16712
8. Total Reserves (%) (7/2)x100	37.1	58.3	38.6	57.2	41.5	59.8
9. Scheduled Maintenance	1035	2154	1559	4689	1459	5414
10. Capability after Maintenance (6-9)	43099	42108	42369	40151	43334	39265
11. Reserves after Maintenance (10-2)	10919	14141	10683	11622	11680	11298
12. Reserves after Maintenance (%) (11/2)x100	33.9	50.6	33.7	40.7	36.9	40.4
13. Inoperable Capability	2163	1871	2548	523	725	1167
14. Available Capability (10-13)	40936	40237	39821	39628	42609	38098
15. Available Reserves (14-2)	8756	12270	8135	11099	10955	10131
16. Available Reserves (%) (15/2)x100	27.2	43.9	25.7	38.9	34.6	36.2
17. Forced Outages	5928	6802	1907	3739	6519	8283
18. Actual Capability after Forced Outages (14-17)	35008	33435	37914	35889	36090	29815
19. Actual Reserves (18-2)	2828	5468	6228	7360	4436	1848
20. Actual Reserves (%) (19/2)x100	8.8	19.6	19.7	25.8	14.0	6.6

Table 3A.13

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
PJM Region

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability	44755	48809
2. Peak Demand	33550	29850
3. Planned Reserves (1-2)	11205	18959
4. Planned Reserves (%) (3/2)x100	33.4	63.5
5. Net Transactions (Imports-Exports)	157	157
6. Total Capability (1+5)	44912	48966
7. Total Reserves (6-2)	11362	19116
8. Total Reserves (%) (7/2)x100	33.9	64.0
9. Scheduled Maintenance	1300	4550
10. Capability after Maintenance (6-9)	43612	44416
11. Reserves after Maintenance (10-2)	10062	14566
12. Reserves after Maintenance (%) (11/2)x100	30.0	48.8
13. Inoperable Capability	28	281
14. Available Capability (10-13)	43584	44135
15. Available Reserves (14-2)	10034	14285
16. Available Reserves (%) (15/2)x100	29.9	47.9
17. Forced Outages	0	0
18. Actual Capability after Forced Outages (14-17)	43584	44135
19. Actual Reserves (18-2)	10034	14285
20. Actual Reserves (%) (19/2)x100	29.9	47.9

Table 3A.14.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
PJM Region

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	46010	48588	47301	49869	48413	51000	49085	51683
2. Peak Demand	34550	30980	35610	32000	36590	33080	37600	34230
3. Planned Reserves (1-2)	11460	17608	11691	17869	11823	17920	11485	17453
4. Planned Reserves (%) (3/2)x100	33.2	56.8	32.8	55.8	32.3	54.2	30.5	51.0
5. Net Transactions (Imports-Exports)	107	107	107	107	107	107	107	107
6. Total Capability (1+5)	46117	48695	47408	49976	48520	51107	49192	51790
7. Total Reserves (6-2)	11567	17715	11798	17376	11930	18027	11592	17560
8. Total Reserves (%) (7/2)x100	33.5	57.2	33.1	56.2	32.6	54.5	30.8	51.3
9. Scheduled Maintenance	1400	4550	1450	4700	1550	4850	1600	4950
10. Capability after Maintenance (6-9)	44717	44145	45958	45276	46970	46257	47592	46840
11. Reserves after Maintenance (10-2)	10167	13165	10348	13276	10380	13177	9992	12610
12. Reserves after Maintenance (%) (11/2)x100	29.4	42.5	29.1	41.5	28.4	39.8	26.6	36.8
13. Inoperable Capability	259	281	231	253	120	128	120	128
14. Available Capability (10-13)	44458	43864	45727	45023	46850	46129	47472	46712
15. Available Reserves (14-2)	9908	12884	10117	13023	10260	13049	9872	12482
16. Available Reserves (%) (15/2)x100	28.7	41.6	28.4	40.7	28.0	39.4	26.3	36.5
17. Forced Outages 1/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	44458	43864	45727	45023	46850	46129	47472	46712
19. Actual Reserves (18-2)	9908	12884	10117	13023	10260	13049	9872	12482
20. Actual Reserves (%) (19/2)x100	28.7	41.6	28.4	40.7	28.0	39.4	26.3	36.5

XI.3.19

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	0	0	0	1067
22. Actual Capability (18-21)	44458	43864	45727	45023	46850	46129	47472	45645
23. Actual Reserves with Nuclear Delays (22-2)	9908	12884	10117	13023	10260	13049	9872	11415
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	28.7	41.6	28.4	40.7	28.0	39.4	26.3	33.3

1/ Information not available.

Table 3A.14.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
PJM Region

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	51026	53803	52347	54984	54858	57448	55661	58245	56546	59110
2. Peak Demand	38600	35370	39600	36530	40550	37560	41440	38610	42370	39670
3. Planned Reserves (1-2)	12426	18433	12747	18454	14318	19888	14221	19635	14176	19440
4. Planned Reserves (%) (3/2)x100	32.2	52.1	32.2	50.5	35.3	52.9	34.3	50.9	33.5	49.0
5. Net Transactions (Imports-Exports)	107	107	107	107	107	107	107	107	107	107
6. Total Capability (1+5)	51133	53910	52454	55091	54975	57555	55768	58352	56653	59217
7. Total Reserves (6-2)	12533	18540	12854	18561	14425	19995	14328	19742	14283	19547
8. Total Reserves (%) (7/2)x100	32.5	52.4	32.5	50.8	35.6	53.2	34.6	51.1	33.7	49.3
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	51133	53910	52454	55091	54975	57555	55768	58352	56653	59217
11. Reserves after Maintenance (10-2)	12533	18540	12854	18561	14425	19995	14328	19742	14283	19547
12. Reserves after Maintenance (%) (11/2)x100	32.5	52.4	32.5	50.8	35.6	53.2	34.6	51.1	33.7	49.3
13. Inoperable Capability	520	528	520	528	812	824	812	824	812	824
14. Available Capability (10-13)	50613	53382	51934	54563	54163	56731	54956	57528	55841	58393
15. Available Reserves (14-2)	12013	18012	12334	18033	13613	19171	13516	18918	13471	18723
16. Available Reserves (%) (15/2)x100	31.1	50.9	31.1	49.4	33.6	51.0	32.6	49.0	31.8	47.2
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	50613	53382	51934	54563	54163	56731	54956	57528	55841	58393
19. Actual Reserves (18-2)	12013	18012	12334	18033	13613	19171	13516	18918	13471	18723
20. Actual Reserves (%) (19/2)x100	31.1	50.9	31.1	49.4	33.6	51.0	32.6	49.0	31.8	47.2

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	1067	0	0	0	0	0	0
22. Actual Capability (18-21)	50613	53382	51934	53496	54163	56731	54956	57528	55841	58393
23. Actual Reserves with Nuclear Delays (22-2)	12013	18012	12334	16939	13513	19171	13516	18918	13471	18723
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	31.1	50.9	31.1	46.4	33.6	51.0	32.6	49.0	31.8	47.2

1/ Information not available.

SECTION XI.4

MID-AMERICA INTERPOOL NETWORK

(MAIN)

MID-AMERICA INTERPOOL NETWORK
(MAIN)

The Main region includes all of Illinois and parts of Michigan, Wisconsin and Missouri. The planning of construction and the utilization of generation and transmission facilities for purposes of improved reliability and adequacy of bulk power supply within the region are coordinated through a formal agreement, the Mid-America Interpool Network (MAIN), which was originally signed by participants in 1964. There are 13 regular members of MAIN, composed of investor-owned, rural cooperatives and municipal power suppliers, and four associate members. Collectively, these utilities represent essentially all the power resources within the region.

Additional coordination within MAIN is effected through agreements among the various utility systems and several power pooling groups have been formed: the Illinois-Missouri Pool (ILLMO); the Wisconsin Power Pool (WIPP) and the Wisconsin-Upper Michigan Systems (WUMS).

The power pools can be geographically grouped within the following DOE Electric Region boundaries:

Electric Region 6 - Commonwealth Electric Company: Commonwealth Edison Company

Electric Region 17 - Illinois-Missouri Group: ILLMO Pool

Electric Region 19 - Wisconsin-Upper Michigan Systems Group: WUMS and WIPP Pools

COMMONWEALTH EDISON COMPANY-CECOELECTRIC REGION 6

Electric Region 6 geographically covers the northern portion of Illinois and is comprised essentially of the service area of the Commonwealth Edison Company. In addition to Commonwealth Edison, data for two small Illinois municipal electric systems within the same geographic area are included in this report -- Rochelle, Illinois and Winnetka, Illinois. These electric systems data are included also in the main ERA-411 report. The region has a diverse mixture of commerce, industry and agriculture.

The electric systems in the region provide service to eight million people in an 11,525 square mile area including about 400 municipalities and the city of Chicago. They serve approximately 2.9 million customers, 2.6 million are residential and the remainder commercial and industrial customers. The utility has 765 kV and 345 kV interconnections with the Indiana and Michigan Electric Company in ECAR and 345 kV ties with Northern Indiana Public Service Company, also in ECAR. In addition, there are 345 kV ties with the Illinois Power Company, Central Illinois Light Company and Wisconsin Electric Power in MAIN and with Iowa-Illinois in MARCA.

The Commonwealth Edison Company has approximately 40 percent of the total generating capability in MAIN and is a major subgroup of the MAIN organization.

Historical Perspective

CECO has historically been a summer-peaking region. The summer and winter peaks for the period 1977-1979 are shown below.

Table 4A.1

Historical Peak Demand-MW
CECO Region

	<u>S U M M E R</u>				<u>W I N T E R</u>		
	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>December</u>	<u>January</u>	<u>February</u>
1977	12,236	13,932	10,211	10,733	10,551	10,726	10,057
1978	12,851	<u>13,517</u>	13,675	13,720	10,423	<u>11,068</u>	10,728
1979	12,146	12,553	<u>13,804</u>	<u>11,446</u>	10,527	<u>10,715</u>	10,252

Underline indicates seasonal peak

The summer peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August, but in 1978 it occurred in September.

The winter peak usually occurs in January and generally is in the order of 20 percent less than the summer peak. Advantage is taken of this difference in magnitude between the summer and winter peaks for the performance of scheduled maintenance. The following table shows the scheduled maintenance performed each period and also the capability unavailable because of forced outages or otherwise inoperable.

Table 4A.2

SCHEDULED MAINTENANCE AND UNAVAILABLE CAPABILITIES
CECO REGION

	<u>S U M M E R</u>			<u>W I N T E R</u>		
	<u>Scheduled</u> <u>Mainten-</u> <u>ance</u> <u>(MW)</u>	<u>Other</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Total</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Scheduled</u> <u>Mainten-</u> <u>ance</u> <u>(MW)</u>	<u>Other</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>	<u>Total</u> <u>Unavail-</u> <u>able</u> <u>(MW)</u>
1977	207	4,104	4,311	1,186	5,953	7,139
1978	0	4,070	4,070	1,803	5,040	6,843
1979	207	4,841	5,048	1,261	7,785	9,046

The capability unavailable for reasons other than scheduled maintenance varied from 21-28 percent of the planned capability in summer and from 29-44 percent in winter.

The reserve margins for the 1977-1979 seasonal periods are shown below, considering the effects of scheduled maintenance and other outages.

XI.4.3

Table 4A.3

HISTORICAL SEASONAL RESERVES CECO REGION

S U M M E R

	Peak Demand (MW)	Total Capa- bility (MW)	Total Reserves (%)	Avail- able Capa- bility (MW)	Avail- able Reserves (%)	Available Capability After Forced Outages (MW)	Actual Reserves (%)
1977	13,932	18,459	32.5	18,252	31.0	14,148	1.6
1978	13,720	17,947	30.8	17,947	30.8	13,877	1.1
1979	13,804	19,212	39.2	19,005	47.6	14,164	2.6

W I N T E R

1977	10,726	17,966	67.5	16,780	56.4	10,827	0.9
1978	11,068	18,144	63.9	16,341	47.6	11,301	2.1
1979	10,715	20,630	92.5	19,369	80.8	11,584	8.1

The actual reserves were able to meet the peaks in the 1977-1979 period after taking into account both scheduled and unscheduled outages and still have a small excess of capacity. It should be noted that without a large amount of power import each year, the available capability to meet the peak requirements would have been insufficient. Purchases varied from 12 to 19 percent of summer peak demand in 1977-1979. The energy requirements, summer demands, winter demands, and annual load factors for the 1977-1979 period are shown below.

Table 4A.4

HISTORICAL ENERGY, PEAKS AND LOAD FACTORS CECO REGION

	Energy Requirement (GWH)		Summer Demand (MW)		Winter Demand (MW)		Annual Load Factor
		Growth %		Growth %		Growth %	
1977	65,103	-	13,932	-	10,726	-	53.3
1978	67,927	4.3	13,720	(1.5)	11,068	3.2	56.5
1979	67,650	(0.4)	13,804	0.6	10,715	(3.2)	55.9
% Growth 1977-1979		1.9		(0.5)		0.0	

XI.4.4

During the 1977-1979 period, the energy requirements grew at a compound growth rate of 1.9 percent. This was considerably below the previous long-term growth rate. The reduction in the energy growth was due essentially to conservation efforts and slow down in economic growth of the area.

The summer and winter peak demands have essentially zero growth in this period. This no-growth in the demands was caused by a combination of economics, climatic conditions and conservation efforts. The depressed demands have resulted in increased load factors in 1978 and 1979 compared with 1977.

Current Perspective

The projected 1980 summer and winter demands are shown below.

Table 4 A.5

PROJECTED 1980 SEASONAL PEAK DEMAND* MW
CECO REGION

<u>Summer</u>			<u>Winter</u>		
<u>June</u>	<u>July</u>	<u>August</u>	<u>December</u>	<u>January</u>	<u>February</u>
14,382	15,139	14,838	11,068	11,178	10,736

*Coincident as to month

These demands are projected to occur, respectively, in July and January, which is consistent with previous occurrences. The winter demand is estimated to be 26 percent less than the summer demand. The reduced level of the winter demand will afford time to perform scheduled maintenance. There are 2,839 MW of capacity scheduled for maintenance during the winter period. No maintenance is scheduled for the summer period. This is approximately 15 percent of the winter planned capability. The 1980 summer planned capability of CECO is estimated to be 17,352 MW and the summer peak demand is projected to be 15,139 MW, resulting in planned reserve of 2,213 MW or 14.6 percent. After adjustments for scheduled receipts and deliveries the total reserve is increased to 2,844 or 18.8 percent. With adjustments for the scheduled unavailable capacity during the summer peak period, the available reserve is projected to be 2,647 MW or 17.5 percent. The summer and winter 1980 reserve margins for the electric region are shown below.

Table 4A.6

1980 RESERVE MARGINS*
CECO REGION

<u>S U M M E R</u>						<u>W I N T E R</u>					
<u>Planned Reserves</u>		<u>Total Reserves</u>		<u>Available Reserves</u>		<u>Planned Reserves</u>		<u>Total Reserves</u>		<u>Available Reserves</u>	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
2213	14.6	2844	18.8	2647	17.5	7786	69.7	8417	75.3	5371	48.0

*Based on ERA Form 411

The margins shown above are not adjusted for unscheduled outages of capacity as the amount of these outages are unknown at present. If these outages are in the order of magnitude that they were in the 1977-1979, large amounts of power will have to be imported as in the 1977-1979 period to cover deficits. Transfer could be as high as 2,200 MW based on outage rates of 29 percent, the maximum in the 1977-1979 period. However, it is standard procedure for the area to depend on the transmission network to supply two-thirds of its reserve obligation and its own capability to supply one-third.

The planned reserve requirement of systems in this Region is governed by MAIN operating guide H-6, "Procedure for Determination of Generating Reserve Requirements." Currently, Commonwealth Edison Company's reserve margin criteria is 14 percent (2,119 MW) during summer 1980 and 24 percent (2,682 MW) during winter 1980. The company's forecasted margins of 2,213 MW and 7,786 MW, respectively, exceeds the established criteria.

In addition to planned reserve criteria, the MAIN Operating Guide No. 5 governs the "Minimum Operating Reserve of Generating Capacity." Operating reserve is defined as the sum of spinning reserve connected to the bus which can be fully applied within ten minutes plus capacity not connected to the bus but which is capable of being effected in ten minutes or less.

XI.4.6

The minimum operating reserve required in MAIN is 1.5 times the winter normal capability of the largest generating unit in commercial service in MAIN. The minimum spinning reserve is 50 percent of the operating reserve requirements. The operating reserve of MAIN is distributed among the three subgroups of MAIN in proportion to the winter normal rating of the largest unit in service in each subregion to the sum of the ratings of the largest unit in service in the three subgroups, which for CECO is 47.9 percent. This allocation assures the best distribution of the reserves. The current operating and spinning reserve requirements of the CECO subgroup are shown below.

Winter normal rating of largest unit in MAIN	1,040 MW
Total operating reserve obligation of MAIN (1.5 x largest unit)	1,560 MW
Operating reserves-CECO portion (47.9 percent)	747 MW
Minimum level of spinning reserves (50 percent of operating reserves)	374 MW

The summer planned generating capability in CECO, for 1980 was 17,352 MW, and is shown below by type of fuel.

Table 4 A.7

1980 SUMMER PLANNED CAPABILITY IN MW CECO REGION

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capa- bility
			ST	CT	IC	ST	CT	IC	Conv.	R.S.	
	4,975	7,536	3,200	1,488	31	26	16	-	-	-	17,352
% of total	28.7	43.4	18.9	8.6	0.2	0.1	0.1				100.0

There are seven nuclear units installed in the region, comprising 29 percent of the current capability. Coal-fired steam units represent 43 percent of the total capability and oil-fired steam units, represent 19 percent. There are no new coal units scheduled for installation before December 1980 in the region, so the summer reserve situation will not be affected.

There is a 1,048 MW nuclear unit (LaSalle County 1) scheduled for installation in December 1980. If this unit were delayed beyond the start of the winter peak season, the available reserves would be reduced to 4,323 MW (38.7 percent). This is within the region's reserve requirement winter criteria of 24 percent.

The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown below.

Table 4A.8

1980 REQUIREMENTS
CECO REGION

	<u>Energy Requirement</u> (GWH)	<u>Summer Demand</u> (MW)	<u>Winter Demand</u> (MW)	<u>Annual</u> <u>L.F.</u> (%)
	69,244	15,139	11,178	52.2
% growth 1980-79	2.4	9.7	4.3	

The 1980 summer and winter demands are projected to grow at considerably higher rates than they did during the 1977-1979 period. This is do in part to the result of over estimation of the 1979/1980 winter peak, and also the summer of 1979. Although the peaks and energy are forecasted to grow at a rate faster than during the 1977-1979 period, the projected 1980 values are considerably below what were projected last year. If lower than projected 1980 demands occur, there will be an enhancement of the reserve situation.

The projected 1980 annual load factor, 52.2 percent, is lower than that experienced during the 1977-1979 period. Delays of future critical bulk power transmission facilities that will not be in service when needed are required to be reported under Item 5-C of the ERA 411 report. In the April 11, 1980 MAIN report, no delays are reported for the CECO region.

Future Perspective

The range of total reserves for the CECO region for the periods 1981-1985 and 1986-1989 are tabulated below.

Table 4A.9

RANGE OF TOTAL RESERVE-PERCENT
CECO REGION

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
19.1-29.0	77.8-90.0	13.3-22.9	64.1-74.2

The summer reserve margin exceeds the 14 percent MAIN reserve requirements criteria for all years in the 1981-1985 period but drops below it in 1988. It is anticipated that arrangements will be made to purchase the capacity from the excess available to purchase in MAIN if additional capacity is not installed. The winter reserve margin exceeds the 24 percent reserve criteria in all years. Scheduled maintenance is not shown for the 1986-1989 period in the MAIN ERA 411 report. These are usually in the order of 2,000-3,000 MW. Allowance for 2,500 MW for maintenance outages in the 1986-1989 period would reduce the range of available reserve to 47.7-58.1 percent.

The projected growth rates of demand and energy for each period and the overall rates for 1981-1989 are shown below.

Table 4A.10

PROJECTED ENERGY AND DEMAND GROWTH RATES
CECO REGION

<u>Energy Requirements</u>			<u>Summer Demand</u>		<u>Winter Demand</u>		<u>Annual Load Factor</u>
<u>1000</u>	<u>Growth</u>		<u>Growth</u>		<u>Growth</u>		
<u>(MWH)</u>	<u>%</u>		<u>(MW)</u>	<u>%</u>	<u>(MW)</u>	<u>%</u>	<u>%</u>
1981 72,561	4.8		15,031	4.6	11,628	4.0	53.3
1982 76,108	4.9		16,603	4.9	12,090	4.0	52.3
1983 79,687	4.7		17,344	4.5	12,581	4.0	52.4
1984 82,954	4.1		18,036	4.0	13,083	4.0	52.4
1985 86,352	4.1		18,758	4.0	13,604	4.0	53.6
% Growth 81-85	4.4			4.3		4.0	
1986 89,980	4.2		19,509	4.0	14,146	4.0	52.7
1987 93,757	4.2		20,291	4.0	14,706	4.0	52.7
1988 97,788	4.3		21,084	3.9	15,298	4.0	52.8
1989 101,987	4.3		21,906	3.9	15,909	4.0	53.1
% Growth 86-89	4.3			3.9		4.0	
% Growth 81-89	4.3			4.1		4.0	

The 1981-1985 summer demands are projected to grow at a compound rate of 4.3 percent; 1986-1989, 3.9 percent; and overall 1981-1989, 4.1 percent. These rates are considerably higher than the 1977-1979 period. However, the projected growth rates are close to those of the other regions in MAIN.

The winter demand growth rates are projected to increase to a constant 4.0 percent for the total 1981-1989 period from no growth in the 1977-1979 period.

The energy requirements are projected to grow 4.4 percent from 1981-1985; 4.3 percent from 1986-1989; and 4.3 percent for the overall period 1981-1989. Historically, the energy grew 1.9 percent during the period 1977-1979.

The summer capability of units planned in the region for the period 1980-1989 is shown by type of fuel on Table 4A.19. Generating unit additions during the period are indicated on Table 4 A.20. The capacity percentages for each type of fuel use for the target years 1980, 1984 and 1989 are given below.

Table 4A.11

PLANNED GENERATING CAPABILITY BY TYPE OF FUEL-PERCENT
CECO REGION

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capa- bility
			ST	CT	IC	ST	CT	IC	Conv.	R.S.	
1980	28.7	43.4	18.9	8.6	0.2	0.1	0.1	-	-	-	100.0
1984	45.6	33.1	14.4	6.5	0.1	0.1	0.1	0.1	-	-	100.0
1989	47.0	33.1	13.4	6.1	0.1	0.1	0.1	0.1	-	-	100.0

There are currently 7 nuclear reactors installed in CECO, and one scheduled for December 1980. The following nuclear generating units are scheduled for installation during the 1981-1989 period.

Table 4 A.12

SCHEDULED NUCLEAR ADDITIONS-1981-1989
CECO REGION

<u>System</u>	<u>Station</u>	<u>MW</u>	<u>Type</u>	<u>Effective Date</u>
CECO	LaSalle County 2	1,048	BWR	12/81
	Byron 1	1,120	PWR	10/82
	Braidwood 1	1,090	PWR	10/83
	Byron 2	1,120	PWR	10/83
	Braidwood 2	1,090	PWR	10/84

All of the units are scheduled to be in service prior to the start of the corresponding winter peak season. If these units are delayed until after the peak occurred in each year they are to be in-service, the effects on the reserve would be minimal. The resultant reserves available each year would still exceed the winter MAIN reserve criteria of 24 percent by a large margin.

A 550 MW fossil-fired steam unit is scheduled for October 1988 and another 550 MW unit, for April 1989. A delay in the first unit would reduce the winter 1988 available reserve to 60.5 percent. A delay in the second unit would reduce the summer 1989 available reserve to 11.6 percent which would be below the 14 percent minimum summer reserve requirements.

The adequacy and reliability of the region's transmission network is tested periodically for contingency conditions in accordance with the MAIN operating guide No. 2. The results of the investigation for the 1984 Emergency Transfer Capabilities (ETC's) for the CECO are outlined below.

General Observations

The Edison system modeled in this study was the currently planned generation and transmission system for 1984. System additions during the period 1979 to 1984 include 7166 MW of generation and 4000 MVA of EHV transformer capability. Anticipated EHV line additions include several lines associated with new generating capacity plus other lines required for bulk power system reinforcement. No additional tie lines are proposed for this time period.

The transmission system ETC as determined by this study is considered adequate to meet Edison's currently projected needs for 1984. Except for CE exports to WUMS (900 MW) and MINN (400 MW), all ETC's were equal to or greater than those found in the previous 1982 study. CE exports to WUMS were only 100 MW lower and CE exports to MINN were 150 MW lower.

Table 4A.13

1984 EMERGENCY TRANSFER CAPABILITY (ETC)
CECO REGION

<u>Import From</u>	<u>ETC (MW)</u>	<u>Limiting Element</u>
ECAR	3400	Dumont-Babcock 345 kV
IOWA	1700	Marshfield-Clark Co. 115 kV
	1700(1)	Wien-T Corners 115 kV
	900(1)	Cassel-Wien 115 kV
	350(1)	T Corners-Wissota 115 kV
MINN	500	Alma-Wabaco 161 kV
	450(1)	Cassel-Wien 115 kV
	200(1)	T Corners-Wissota 115 kV
MO	1400	Dardenne-Pike 161 kV
SCILL	1800	Ind. Park-Meredosia 138 kV
TVA	3500	Electric Jct.-Lombard 345 kV
WUMS	1200	Zion-Pleasant Prairie 345 kV
	450(1)	Waukegan-Kenosha 138 kV
<u>Export To</u>	<u>ETC (MW)</u>	<u>Limiting Element</u>
ECAR	5000+	No Limit Found
IOWA	800	Calamus-Maquoketa 161 kV
MINN	400	Genoa-Lacrosse Tap 161 kV
MO	1100	Cahokia 345/138 kV Trfr.
SCILL	2000+	No Limit Found
TVA	3600	Quad Cities-Sub 91 345 kV
WUMS	900	Electric Jct.-Lombard 345 kV

- (1) Limitation is not recognized as a valid constraint on transfer capability because line can be opened under emergency conditions.

The interregional transfer capabilities as determined from this study are as follows. These are approximate nonsimultaneous values above contracted schedules, based on emergency transfer capabilities.

Table 4 A.14

1984 MAIN EMERGENCY TRANSFER CAPABILITY-MW
CECO REGION

ECAR	to MAIN	2900 MW
MARCA	to MAIN	800 MW
SERC	to MAIN	2800 MW
SPP	to MAIN	1900 MW
MAIN	to ECAR	4000+ MW
MAIN	to MARCA	550 MW
MAIN	to SERC	3200 MW
MAIN	to SPP	1800 MW

Table 4A.15

LIST OF PROPOSED BULK POWER LINES - 1/1/80 TO 1/1/90
COMMONWEALTH EDISON COMPANY REGION

Line Ownership List	Terminals	Line Length Miles	Expected Service Date	Nominal Voltage in kV		Notes
				Oper	Design	
CECO	Braidwood-East Frankfort	36	10/80	345	345	Deliver Generator Output
CECO	Braidwood-East Frankfort	36	10/80	345	345	Deliver Generator Output
CECO	Braidwood-Existing Line	5	10/80	345	345	Deliver Generator Output
CECO	Braidwood-Existing Line	5	10/80	345	345	Deliver Generator Output
CECO	Braidwood-Davis Creek	23	5/81	345	345	Deliver Generator Output
CECO	Braidwood-Davis Creek	23	5/81	345	345	Deliver Generator Output
CECO	LaSalle-Plano	42	7/81	345	345	Deliver Generator Output
CECO	LaSalle-Plano	42	7/81	345	345	Deliver Generator Output
CECO	Byron-Existing Line	8	12/81	345	345	Deliver Generator Output
CECO	Byron-Cherry Valley	21	5/83	345	345	Deliver Generator Output
CECO	Byron-Wempletown	30	5/83	345	345	Deliver Generator Output
CECO	Davis Creek-Crete	34	5/84	345	345	Deliver Generator Output
CECO	Davis Creek-Crete	34	5/84	345	345	Deliver Generator Output
CECO	Electric Junction-Wayne	14	5/85	345	345	Relieve Overloads
CECO	Crete-Bloom	5	5/86	345	345	Relieve Overloads
CECO	Bloom-Burnham	12	5/86	345	345	Relieve Overloads
CECO/WILP	Wempletown-Paddock	11	7/86	345	345	Increase Transfer Capability Miles Shown for CECO Portion
CECO	Langham-Existing Line	4	4/87	345	345	Relieve Overloads
CECO	Wayne-Itasca	15	5/88	345	345	Deliver Generator Output
CECO	Langham-Existing Line	4	7/88	345	345	Deliver Generator Output
CECO	Langham-Existing Line	12	7/88	345	345	Deliver Generator Output
CECO	Langham-Existing Line	12	7/88	345	345	Deliver Generator Output
CECO	Collins-Existing Line	9	7/88	345	345	Deliver Generator Output
CECO	Dresden-Existing Line	.1	7/88	345	345	Deliver Generator Output
CECO	ERIE North-Existing Line	7	4/89	345	345	Deliver Generator Output

Table 4A.16

HISTORICAL CAPABILITY AND RESERVE MARGINS
COMMONWEALTH EDISON COMPANY REGION

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	15,865	16,909	16,264	17,303	17,290	17,824
(2) Peak Demand (MW)	13,932	10,726	13,720	11,068	13,804	10,715
(3) Planned Reserve (MW) (1-2)	1,933	6,183	2,544	6,235	3,486	7,109
(4) Planned Reserve (%) (3-2) x 100	13.9	57.6	18.5	56.3	25.3	66.3
(5) Net Transactions ^{1/} (MW)	2,594	1,057	1,683	841	1,922	2,806
(6) Total Capability (MW) (1+5)	18,459	17,966	17,947	18,144	19,212	20,630
(7) Total Reserve (MW) (6-2)	4,527	7,240	4,227	7,076	5,408	9,915
(8) Total Reserve (%) (7-2) x 100	32.5	67.5	30.8	63.9	39.2	92.5
(9) Scheduled Maintenance (MW)	207	1,186	0	1,803	207	1,261
(10) Capability after Maintenance (MW) (6-9)	18,252	16,780	17,947	16,341	19,005	19,369
(11) Reserve after Maintenance (MW) (10-2)	4,320	6,054	4,227	5,273	5,201	8,654
(12) Reserve after Maintenance (%) (11-2) x 100	31.0	56.4	30.8	47.6	37.7	80.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	18,252	16,780	17,947	16,341	19,005	19,369
(15) Available Reserve (MW) (14-2)	4,320	6,054	4,227	5,273	5,201	8,654
(16) Available Reserve (%) (15-2) x 100	31.0	56.4	30.8	47.6	37.7	80.8
(17) Forced Outages (F.O.) (MW)	4,104	5,953	4,070	5,040	4,841	7,785
(18) Available Capability after F.O. (MW) (14-17)	14,148	10,827	13,877	11,301	14,164	11,584
(19) Actual Reserve (MW) (18-2)	216	101	157	233	360	869
(20) Actual Reserve (%) (19-2) x 100	1.6	0.9	1.1	2.1	2.6	8.1

^{1/} Net Transactions = Purchases - Sales

Table 4A.17

CURRENT CAPABILITY AND RESERVE MARGINS
COMMONWEALTH EDISON COMPANY REGION

		1980	
		<u>Summer</u>	<u>Winter</u>
(1)	Planned Capability (MW)	17,352	18,964
(2)	Peak Demand (MW)	15,139	11,178
(3)	Planned Reserve (MW) (1-2)	2,213	7,786
(4)	Planned Reserve (%) (3-2) x 100	14.6	69.7
(5)	Net Transactions <u>1/</u> (MW)	631	631
(6)	Total Capability (MW) (1+5)	17,983	19,595
(7)	Total Reserve (MW) (6-2)	2,844	8,417
(8)	Total Reserve (%) (7-2) x 100	18.8	75.3
(9)	Scheduled Maintenance (MW)	0	2,839
(10)	Capability after Maintenance (MW) (6-9)	17,983	16,756
(11)	Reserve after Maintenance (MW) (10-2)	2,844	5,578
(12)	Reserve after Maintenance (%) (11-2) x 100	18.8	49.9
(13)	Inoperable Capability (MW)	197	207
(14)	Available Capability (MW) (10-13)	17,786	16,549
(15)	Available Reserve (MW) (14-2)	2,647	5,371
(16)	Available Reserve (%) (15-2) x 100	17.5	48.0
(17)	Forced Outages (F.O.) (MW)	0	0
(18)	Available Capability after F.O. (MW) (14-17)	17,786	16,549
(19)	Actual Reserve (MW) (18-2)	2,647	5,371
(20)	Actual Reserve (%) (19-2) x 100	17.5	48.0

1/ Net Transactions = Purchases - Sales

Table 4A.18

FUTURE CAPABILITY AND RESERVE MARGINS
COMMONWEALTH EDISON COMPANY REGION

	1981		1982		1983	
	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	18,400	20,042	19,448	21,174	20,580	23,414
(2) Peak Demand (MW)	15,831	11,628	16,603	12,090	17,344	12,581
(3) Planned Reserve (MW) (1-2)	2,569	8,414	2,845	9,084	3,236	10,833
(4) Planned Reserve (%) (3-2) x 100	16.2	72.4	17.1	75.1	18.7	86.1
(5) Net Transactions ^{1/} (MW)	631	631	332	332	320	320
(6) Total Capability (MW) (1+5)	19,031	20,673	19,780	21,506	20,900	23,734
(7) Total Reserve (MW) (6-2)	3,200	9,045	3,177	9,416	3,556	11,153
(8) Total Reserve (%) (7-2) x 100	20.2	77.8	19.1	77.9	20.5	88.6
(9) Scheduled Maintenance (MW)	0	1,936	0	1,960	0	3,147
(10) Capability after Maintenance (MW) (6-9)	19,031	18,737	19,780	19,546	20,900	20,587
(11) Reserve after Maintenance (MW) (10-2)	3,200	7,109	3,177	7,456	3,556	8,006
(12) Reserve after Maintenance (%) (11-2) x 100	20.2	61.1	19.1	61.7	20.5	63.6
(13) Inoperable Capability (MW)	197	207	197	207	197	207
(14) Available Capability (MW) (10-13)	18,834	18,530	19,583	19,339	20,703	20,380
(15) Available Reserve (MW) (14-2)	3,003	6,902	2,980	7,249	3,359	7,799
(16) Available Reserve (%) (15-2) x 100	19.0	59.4	17.9	60.0	19.4	62.0
(17) Forced Outages (F.O.) (MW)	0	0	0	0	0	0
(18) Available Capability after F.O. (MW) (14-17)	18,834	18,530	19,583	19,339	20,703	20,380
(19) Actual Reserve (MW) (18-2)	3,003	6,902	2,980	7,249	3,359	7,799
(20) Actual Reserve (%) (19-2) x 100	19.0	59.4	17.9	60.0	19.4	62.0

^{1/} Net Transactions = Purchases - Sales

Table 4A.18

FUTURE CAPABILITY AND RESERVE MARGINS
COMMONWEALTH EDISON COMPANY REGION

	1984		1985		1986	
	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	22,790	24,534	23,885	24,539	23,885	24,539
(2) Peak Demand (MW)	18,036	13,083	18,758	13,604	19,509	14,146
(3) Planned Reserve (MW) (1-2)	4,754	11,451	5,127	10,935	4,376	10,393
(4) Planned Reserve (%) (3-2) x 100	26.4	87.5	27.3	80.4	22.4	73.5
(5) Net Transactions 1/ (MW)	322	322	322	322	97	97
(6) Total Capability (MW) (1+5)	23,112	24,856	24,207	24,861	23,982	24,636
(7) Total Reserve (MW) (6-2)	5,076	11,773	5,449	11,257	4,473	10,490
(8) Total Reserve (%) (7-2) x 100	28.1	90.0	29.0	82.7	22.9	74.2
(9) Scheduled Maintenance (MW)	0	2,327	0	0	0	0
(10) Capability after Maintenance (MW) (6-9)	23,112	22,529	24,207	24,861	23,982	24,636
(11) Reserve after Maintenance (MW) (10-2)	5,076	9,446	5,449	11,257	4,473	10,490
(12) Reserve after Maintenance (%) (11-2) x 100	28.1	72.2	29.0	82.7	22.9	74.2
(13) Inoperable Capability (MW)	197	207	197	207	0	0
(14) Available Capability (MW) (10-13)	22,915	22,322	24,010	24,654	23,982	24,636
(15) Available Reserve (MW) (14-2)	4,879	9,239	5,252	11,050	4,473	10,490
(16) Available Reserve (%) (15-2) x 100	27.1	70.6	28.0	81.2	22.9	74.2
(17) Forced Outages (F.O.) (MW)	0	0	0	0	0	0
(18) Available Capability after F.O. (MW) (14-17)	22,915	22,322	24,010	24,654	23,982	24,636
(19) Actual Reserve (MW) (18-2)	4,879	9,239	5,252	11,050	4,473	10,490
(20) Actual Reserve (%) (19-2) x 100	27.1	70.6	28.0	81.2	22.9	74.2

1/ Net Transactions = Purchases - Sales

Table 4A.18

FUTURE CAPABILITY AND RESERVE MARGINS
COMMONWEALTH EDISON COMPANY REGION

	1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	23,885	24,539	23,885	25,089	24,985	26,189
(2) Peak Demand (MW)	20,291	14,706	21,084	15,298	21,906	15,909
(3) Planned Reserve (MW) (1-2)	3,594	9,833	2,801	9,791	3,079	10,280
(4) Planned Reserve (%) (3-2) x 100	17.7	66.9	13.3	64.0	14.1	64.6
(5) Net Transactions ^{1/} (MW)	323	323	11	11	11	11
(6) Total Capability (MW) (1+5)	24,208	24,862	23,896	25,100	24,996	26,200
(7) Total Reserve (MW) (6-2)	3,917	10,156	2,812	9,802	3,090	10,291
(8) Total Reserve (%) (7-2) x 100	19.3	69.1	13.3	64.1	14.1	64.7
(9) Scheduled Maintenance (MW)	0	0	0	0	0	0
(10) Capability after Maintenance (MW) (6-9)	24,208	24,862	23,896	25,100	24,996	26,200
(11) Reserve after Maintenance (MW) (10-2)	3,917	10,156	2,812	9,802	3,090	10,291
(12) Reserve after Maintenance (%) (11-2) x 100	19.3	69.1	13.3	64.1	14.1	64.7
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	24,208	24,862	23,896	25,100	24,996	26,200
(15) Available Reserve (MW) (14-2)	3,917	10,156	2,812	9,802	3,090	10,291
(16) Available Reserve (%) (15-2) x 100	19.3	69.1	13.3	64.1	14.1	64.7
(17) Forced Outages (F.O.) (MW)	0	0	0	0	0	0
(18) Available Capability after F.O. (MW) (14-17)	24,208	24,862	23,896	25,100	24,996	26,200
(19) Actual Reserve (MW) (18-2)	3,917	10,156	2,812	9,802	3,090	10,291
(20) Actual Reserve (%) (19-2) x 100	19.3	69.1	13.3	64.1	14.1	64.7

^{1/} Net Transactions = Purchases - Sales

Table 4A.19

INSTALLED NET CAPABILITY AS OF JANUARY 1, BY TYPE OF FUEL - MW
COMMONWEALTH EDISON COMPANY REGION

Electric Region 6-CECO	Summer Capability										Total Capability
	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage	
1980	4975	7536	3280	1488	31	26	16	-	-	-	17352
% Total	28.7	43.4	18.9	8.6	0.2	0.1	0.1	-	-	-	100.0
1981	6023	7536	3280	1488	31	26	16	-	-	-	18400
% Total	32.7	41.0	17.8	8.1	0.2	0.1	0.1	-	-	-	100.0
1982	7071	7536	3280	1488	31	26	16	-	-	-	19448
% Total	36.4	38.7	16.9	7.6	0.2	0.1	0.1	-	-	-	100.0
1983	8191	7536	3280	1488	31	26	16	12	-	-	20580
% Total	39.8	36.6	15.9	7.2	0.2	0.1	0.1	0.1	-	-	100.0
1984	10401	7536	3280	1488	31	26	16	12	-	-	22790
% Total	45.6	33.1	14.4	6.5	0.1	0.1	0.1	0.1	-	-	100.0
1985	11491	7536	3280	1488	31	26	16	12	-	-	23880
% Total	48.1	31.6	13.7	6.2	0.1	0.1	0.1	0.1	-	-	100.0
1986	11491	7536	3280	1488	36	26	16	12	-	-	23885
% Total	48.1	31.6	13.7	6.2	0.1	0.1	0.1	0.1	-	-	100.0
1987	11491	7536	3280	1488	36	26	16	12	-	-	23885
% Total	48.1	31.6	13.7	6.2	0.1	0.1	0.1	0.1	-	-	100.0
1988	11491	7536	3280	1488	36	26	16	12	-	-	23885
% Total	40.1	31.6	13.7	6.2	0.1	0.1	0.1	0.1	-	-	100.0
1989	11491	8086	3280	1488	36	26	16	12	-	-	24435
% Total	47.0	33.1	13.4	6.1	0.1	0.1	0.1	0.1	-	-	100.0

Table 4A.20

MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS AND REMOVALS
COMMONWEALTH EDISON COMPANY REGION

DOE/ERA Electric Region	System	Station	Unit Type	Fuel Type	Net Summer Capability	In-Service Date 1/	
						4/1/79 Report	4/1/80 Report
6	CECO	LaSalle Cty #1	NB <u>2/</u>	UR	1,048	9/79	12/80
6	CECO	LaSalle Cty #2	NB <u>2/</u>	UR	1,048	9/80	12/81
6	CECO	Byron #1	NP <u>3/</u>	UR	1,120	9/81	10/82
6	CECO	Braidwood #1	NP <u>3/</u>	UR	1,090	10/81	10/83
6	CECO	Byron #2	NP <u>3/</u>	UR	1,120	10/82	10/83
6	CECO	Braidwood #2	NP <u>3/</u>	UR	1,090	10/82	10/84
6	CECO	Langham #2	ST	-	550	4/87	10/88
6	CECO	Langham #1	ST	-	550	10/87	4/89
6	CECO	Unidentified #1	ST	-	550	4/88	10/89
6	CECO	Carroll Cty #1	NP <u>3/</u>	UR	817 <u>4/</u>	10/88	-

-
- 1/ Comparison of scheduled in-service dates in the April 1, 1979 and April 1, 1980 Regional Reliability Council Reports.
2/ Boiling Water Reactor.
3/ Pressurized Water Reactor.
4/ Jointly owned by CECO and Iowa Company; Iowa Company's share of 25% is not included in the 1980 "411" report.

ILLINOIS-MISSOURI GROUP (ILLMO)
ELECTRIC REGION 17

Historical Perspective

Electric Region 17 includes all of Illinois except the northern portion plus the eastern portion of Missouri. The major power suppliers in the region are the Central Illinois Public Service Co., Illinois Power Co., and the Union Electric Co. These three electric systems formed a formal power pool in 1952, which coordinates their planning and installation of generating and transmission facilities and the operation of their systems, including emergency and economy exchanges, spinning reserves, and maintenance schedules.

In addition to the three power pool systems, data are included in this electric region for the Central Illinois Light Co.; City of Springfield, Illinois; Southern Illinois Power Cooperative; Western Illinois Power Cooperative; Missouri Power and Light Company; and the City of Columbia, Missouri.

All of the above systems are members or associate members of the Mid-American Interpool Network (MAIN) organization which oversees the coordination of planning, construction, and utilization of generation and transmission facilities of its participants in order to improve the reliability of the electric bulk power supply in the region. The utilities in DOE's Electric Region 17-ILLMO are members of the Illinois and Missouri Groups of MAIN.

The Associated Electric Cooperative, which has been a member of the Missouri Group of MAIN has given notice that it intends to withdraw from MAIN in June 1980. Accordingly, data for this system is not included in this Electric Region and the historical 1977-1979 data has been extracted.

Utilities in the ILLMO Region serve about 1.6 million customers, of which 1.4 million are residential, 161,000 are commercial, and 8,000 are industrial customers.

The utilities in ILLMO have 345 interconnections among themselves; with Indiana Michigan Electric Co. and Public Service Company of Indiana in ECAR; with Illinois Gas and Electric Co. and Iowa Southern Utilities in MARCA; with TVA; and with the Kansas Gas and Electric Co., Public Service Company of Oklahoma, and the Kansas City Power and Light Company in the Southwest Power Pool.

MAIN does not have facilities for regional control of generating capacity or major switching stations nor are such facilities planned in the future. Each system controls its own generating capacity in accordance with procedures established by the NERC (formerly NAPSIC) Operating Committee.

The MAIN Coordination Center is located in Lombard, Illinois, a suburb of Chicago. The principal responsibility of the Center is to assure that the region will meet its load requirements with maximum interconnected system reliability.

ILLMO has historically been a summer peaking region. The region's summer and winter monthly coincident peaks for the period 1977-1979 are shown in Table 4B.1.

Table 4B.1

HISTORICAL PEAK DEMAND* - MW
ILLMO REGION

		<u>Summer</u>			<u>Winter</u>	
	<u>June</u>	<u>July</u>	<u>August</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	9976	11698	10546	8842	9110	8525
1978	11492	11445	11549	8808	9286	9235
1979	10808	11243	12091	8965	8981	8923

Underline indicates seasonal peak.

*Coincident as to month

The summer peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August.

The winter peak usually occurs in January, but it may occur in any winter month, depending on the combination of weather and economic activity in the region. The winter peak during the 1977-1979 period was 20-26 percent less than the corresponding summer peak. Advantage was taken of the difference in magnitude between the seasonal peaks to perform scheduled maintenance. The following table shows the scheduled maintenance performed each period and also the capability unavailable because of forced outages or otherwise inoperable.

Table 4B.2

SCHEDULED MAINTENANCE AND UNAVAILABLE CAPABILITIES
ILLMO REGION

	<u>Summer</u>			<u>Winter</u>		
	<u>Scheduled</u>	<u>Other</u>	<u>Total</u>	<u>Scheduled</u>	<u>Other</u>	<u>Total</u>
	<u>Maintenance</u>	<u>Unavailable</u>	<u>Unavailable</u>	<u>Maintenance</u>	<u>Unavail.</u>	<u>Unavail.</u>
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
1977	33	2130	2163	761	1776	2537
1978	706	903	1609	1427	3056	4483
1979	40	1975	2015	1858	1452	3310

The capability unavailable for reasons other than scheduled maintenance varied from 6-16 percent of the planned capability in summer and from 10-20 percent in winter.

The reserve margins for the 1977-79 peak periods are shown below, considering the effects of scheduled maintenance and other outages.

Table 4B.3

HISTORICAL SEASONAL RESERVES
ILLMO REGION

Summer

	<u>Peak Demand</u> (MW)	<u>Total Capability</u> (MW)	<u>Total Reserves</u> (%)	<u>Avail. Capabil.</u> (MW)	<u>Avail. Reserves</u> (%)	<u>Actual Capabil.</u> (MW)	<u>Actual Reserves</u> (%)
1977	11698	15276	30.6	15243	30.3	13113	12.1
1978	11549	14144	22.5	13438	16.4	12535	8.5
1979	12091	15286	26.4	15246	26.1	13271	9.8

Winter

1977	9110	13122	44.0	12361	35.7	10585	16.2
1978	9286	15083	62.4	13656	47.1	10600	14.2
1979	8981	14615	62.7	12757	42.0	11305	25.9

The actual reserves were more than adequate to meet the peak demands in the 1977-79 period, after taking into account both scheduled and unscheduled outages, although somewhat larger than usually planned. This was caused by a smaller than usual growth in the peak demand.

The energy requirements, summer and winter demands, and annual load factors for the 1977-79 period are shown below.

Table 4B.4

HISTORICAL ENERGY, PEAKS, AND LOAD FACTORS
ILLMO REGION

	<u>Energy</u> Gwh	<u>Requirement</u> Growth %	<u>Summer</u> (MW)	<u>Demand</u> Growth %	<u>Winter</u> (MW)	<u>Demand</u> Growth %	<u>Annual Load Factor</u> %
1977	55091	-	11698	-	9110	-	57.8
1978	56825	3.1	11549	(1.3)	9286	1.9	56.2
1979	57827	1.8	12091	4.7	8981	(3.3)	54.6
% Growth 1977-79		2.5		1.7		(0.7)	

During the period 1977-79 energy requirements grew at a compound rate of 2.5 percent. This is consistent with other regions but is much lower than the previous historical patterns. Both summer and winter demand rates of growth experienced similar declines. The energy and demand low growth rates were a result of conservation efforts, slackening economic conditions, and climatic conditions.

Current Perspective

The projected 1980 summer and winter demands are shown below.

Table 4B.5

PROJECTED 1980 SEASONAL PEAK DEMAND* - MW
ILLMO REGION

Summer				Winter		
June	July	Aug.	Sept.	Dec.	Jan.	Feb.
11503	12542	12203	11319	9771	10086	9569

* Coincident as to month

The winter demand is projected to be 19.6 percent less than the summer demand, which, as in the past, affords opportunity for the performance of scheduled maintenance. There are 1667 MW of capacity scheduled to be out during the winter 1980 peak compared to none during the 1980 summer peak period. This is about 11 percent of the region's planned capability.

The 1980 summer planned capability of the ILLMO region is estimated to be 15,623 MW and the non-coincident summer peak demand is projected to be 12,596 MW, resulting in planned reserves of 3,027 MW or 24.0 percent. After adjustment for scheduled unavailable capacity during the summer peak period, the available reserves are projected to be 3129 MW or 24.8 percent.

The summer and winter 1980 reserve margins for the electric region are shown below.

Table 4B.6

1980 RESERVE MARGINS*
ILLMO REGION

Summer						Winter					
Planned Reserves		Total Reserves		Available Reserves		Planned Reserves		Total Reserves		Available Reserves	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
3027	24.0	3164	25.1	3129	24.8	5540	54.9	5099	50.6	3395	33.7

* Based on ERA Form 411

The margins shown above are not adjusted for unscheduled outages of capacity as the amount of these outages are unknown ahead of time. If these outages do not exceed the maximum outages of the 1977-79 period, 16% of planned capacity during the summer period and 20% during the winter, the resultant reserves would be 629 MW or 5.0% and 270 MW or 2.7%, respectively, in excess of reserve requirements.

The reserve requirements in ILLMO are governed by MAIN Operating Guide #6, "Procedure for Determination of Generator Reserve Requirements." Currently, the minimum reserve requirement for MAIN as a whole is 15%. The available reserves of the Electric Region for the 1980 summer and winter seasons (24.8% and 33.7% respectively) are well above the minimum requirements.

In addition to reserve criteria, the MAIN Operating Guide #5 governs the "Minimum Operating Reserve of Generating Capacity." Operating Reserve is defined as the sum of spinning reserve connected to the bus which can be fully applied within ten minutes plus capacity not connected to the bus but which is capable of being effected in ten minutes or less.

The Minimum Operating Reserve required in MAIN is 1.5 times the winter normal capability of the largest generating unit in commercial service. The Minimum Spinning Reserve is 50 percent of these Operating Reserve requirements. The Operating Reserve of MAIN is distributed among the three subgroups of MAIN in proportion to the winter normal rating of the largest unit in service in each subregion to the sum of the ratings of the largest unit in service in the three subgroups, which for ILLMO is 27.9 percent. This allocation assures the best distribution of the reserves. The current operating and spinning reserve requirements of the ILLMO subgroup is shown below.

Winter Normal Rating of Largest Unit in MAIN - 1040 MW
 Total Reserve Obligation of MAIN (1.5 x Largest Unit) - 1560 MW
 Operating Reserves - ILLMO Portion (27.9%) - 435 MW
 Minimum Level of Spinning Reserves (50% of
 Operating Reserves - 217 MW

The 1980 summer planned generating capability in ILLMO was 15,623 MW, and is shown below by type of fuel.

Table 4B.7

1980 SUMMER PLANNED CAPABILITY (MW)
ILLMO REGION

<u>Nuclear</u>	<u>Coal</u>	<u>Oil</u>			<u>Natural Gas</u>			<u>Hydro</u>		<u>Total</u>
<u>Steam</u>	<u>Steam</u>	<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>Conv.</u>	<u>P.S.</u>	<u>Capability</u>
-	13041	1010	765	38	57	79	-	333	300	15623
% of Total	83.5	6.5	4.9	0.2	0.4	0.5	-	2.1	1.9	100.0

Almost 84% of the current capacity is coal-fired steam; 6% oil-fired steam; and 5% oil-fired combustion capacity. There are no nuclear units installed in the region and hydro is an insignificant portion of the total. There are no new coal-fired steam units scheduled in the region for 1980.

The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown on Table 4B.8

Table 4B-8

1980 LOAD REQUIREMENTS
ILLMO REGION

<u>Energy Requirement</u>	<u>Summer Demand</u>	<u>Winter Demand</u>	<u>Annual L.F.</u>
(GWH)	(MW)	(MW)	(%)
59742	12596	10086	540
% Growth 1980/79: 3.3	4.2	12.3	

The 1980 energy and summer demand requirements are projected to grow at reasonable though somewhat higher rates than they did during the 1977-79 period. The 1980 winter demand rate is inflated, probably the result of an over-estimation of the 1979/80 winter peak. If indeed the 1980 winter forecast is high, reserve margins could benefit throughout the 1980-89 period.

Delays of future critical bulk power transmission facilities that will not be in service when needed is required to be reported under Item 5-C of the ERA 411 report. In the April 1, 1980 MAIN report, it is reported that the Illinois Power Company's Kansas to Sidney 345 kV line originally scheduled for completion in 1977 is now expected to be completed no earlier than the summer of 1983. The delay is primarily due to the intervention of farm groups concerned with land utilization and structure type. The delay could result in some risk to the company's customers in the form of local outages. It was necessary to develop emergency operating plans for the area to minimize impacts on system reliability.

The Central Illinois Public Service Company is also reported to be experiencing a delay of the 345 kV Casey-Kansas-Sidney CLPS-IP line originally scheduled for service in 1977. CLPS section of the line from Casey to Kansas has been completed; but the continued delay of the IP Kansas-Sidney section resulted in some reduction of service reliability to local areas.

Future Perspective

The range of total reserves for ILLMO for the periods 1981-85 and 1986-89 are shown below.

Table 4B.9

RANGE OF TOTAL RESERVES - %
ILLMO REGION

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
18.8-33.3	40.8-63.3	23.1-27.3	32.9-40.2

As indicated above, the reserves exceeds the 15% minimum margin criteria for all the years in each time period based on the posted projected demands and capabilities. The projected growth rates of demand and energy for each period and the overall rates for 1981-1987 are shown on Table 4B.10.

Table 4B.10

PROJECTED ENERGY AND DEMAND GROWTH RATES
ILLMO REGION

	<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	<u>(GWH)</u>	<u>Growth %</u>	<u>(MW)</u>	<u>Growth %</u>	<u>(MW)</u>	<u>Growth %</u>	
1981	62439	4.5	13039	3.5	10541	4.5	54.7
1982	64639	3.5	13468	3.3	11173	6.0	54.8
1983	66996	3.6	13863	2.9	11584	3.7	55.0
1984	69020	3.0	14308	3.2	12305	6.2	54.9
1985	71499	3.6	14750	3.1	12508	1.6	55.3
Growth 1981-85		3.4		3.1		4.4	
1986	74230	3.8	15205	3.1	13284	6.2	55.7
1987	76656	3.3	15713	3.3	13934	4.9	55.7
1988	80014	4.4	16194	3.1	14570	4.6	56.2
1989	83123	3.9	16667	2.9	15660	7.5	56.9
Growth 1986-89		3.8		3.1		5.6	
Growth 1981-89		3.6		3.1		5.1	

The summer demands are projected to grow at a compound rate of growth of 3.1% throughout the entire study period. These rates are considerably higher than the historical 1977-1979 rate of 1.7%, however the period 1977-1979 may be atypical. The winter demand growth rates are projected to increase to 4.4% for the 1981-1985 period and to 5.6% for the 1986-1989 period with an overall 1981-1989 rate of 5.1%. The projected increase in growth rate of the winter demands may not be warranted, especially in view of the negative growth in the 1977-1979 period.

Energy requirements are projected to grow 3.4% from 1981-1985, 3.8% from 1986-1989, and 3.6% for the overall period 1981-1989. Historically, 1977-1979, the energy grew 2.5%. The energy requirements projected growth would indicate optimistic economic activity in the region.

The summer capability of units planned in the region for the period 1980-1989 are shown by type of fuel in Table 4B.22. Major generating unit additions during the period are given in Table 4B.23. Future capability by percent, each type of prime mover, and fuel type for the target years 1980, 1984, and 1989 are shown on Table 4B.11.

Table 4B.11

PLANNED GENERATING CAPABILITY BY TYPE OF FUEL - %
ILLMO REGION

Summer Capability

	Nuclear	Coal	Oil.			Natural Gas			Hydro		Total
	Steam	Steam	ST	CT	IC	ST	CT	IC	Conv.	P.S.	Capability
1980	-	83.5	6.5	4.9	0.2	0.4	0.5	-	2.1	1.9	100.0
1984	11.3	74.8	5.0	4.7	0.2	0.2	0.4	-	1.8	1.6	100.0
1989	15.3	71.8	4.3	4.8	0.2	0.2	0.4	-	1.6	1.4	100.0

Currently, coal is the primary fuel for about 84% of the planned capability of the region. This percentage is projected to decrease to 72% by 1989 due to the installation of three nuclear units in the region; Callaway #1, 1150 MW scheduled for October 1982, Clinton #1, 948 MW scheduled for December 1982 and Callaway #2, 1150 MW scheduled for April 1988. If the in-service dates of the two 1982 units were delayed beyond the start of winter 1982 peak period, reserve requirements would still be greater than the area's reserve requirements. Similarly, a delay in the 1988 unit for one year would not seriously effect reserves.

A major 575 MW coal-fired steam unit Newton #2, is scheduled for service in December 1982. If this unit were delayed past the winter 1982 peak in addition to the planned nuclear units the available reserves would decrease to 17.8%, which still is greater than the minimum MAIN reserve criteria for this region. Five other coal units planned for the area are in the order of 100-450 MW and delays of these units past their respective peak periods should not appreciably reduce the ILLMO reserve margins.

Oil-fired steam units comprise only 6.5% or 1010 MW of the 1980 capability. This is scheduled to decrease to 905 MW by 1985 and to remain at that level in the study period.

The adequacy and reliability of the region's transmission network is evaluated periodically for contingency conditions in accordance with the MAIN Guide No. 2. The results of the investigation of the 1984 Emergency Transfer Capabilities (ETC's) for the South Central Illinois (SCILL) area and the Missouri area follows.

During the time period 1979-1984 generation additions in the South Central Illinois (SCILL) Area totaled 1925 MW. These additions are scheduled for the existing sites of Newton and Duck Creek, as well as the previously undeveloped generating locations of Clinton and an unidentified CWL&P site. Anticipated 345 kV line additions include several lines associated with the new generating additions, plus lines internal to the SCILL Area for the purpose of strengthening the bulk power transmission system. Proposed 345/138 kV transformer additions total approximately 2200 MVA.

Using the criteria of MAIN Guide No. 2, the 1984 SCILL Area was tested to determine interchange capabilities with other areas. The results of this investigation show that SCILL Emergency Transfer Capabilities (ETC's) are judged to be adequate, however, some are lower than desired.

The following tabulation summarizes SCILL ETC's for 1984.

Table 4B.12

1984 Emergency Transfer Capability - Imports
ILLMO REGION - (SOUTH CENTRAL ILLINOIS)

<u>Import From</u>	<u>ETC (MW)</u>	<u>Limiting Facility</u>
CE	2000+	No Limit Found
ECAR	1900(a)	Bunsonville-Eugene 345 kV
IOWA	100	Lakeshire-Watson 138 kV
MINN	150	Lakeshire-Watson 138 kV
MO	550	Meramec 3-Lemay Tap 138 kV
SPP	100	Lakeshire-Watson 138 kV
TVA	2500+	No Limit Found
WUMS	1300(b)	Zion-Pleasant Prairie 345 kV

- (a) The Bunsonville-Eugene 345 kV line is scheduled to be upgraded in 1982. However, the present MVA rating has been used in this study to determine the most restrictive case.
- (b) WUMS to SCILL emergency transfers are more restricted by the Waukegan to Kenosha 138 kV line. This limit is not listed because it is considered to be a local problem.

The Emergency Transfer Capability into SCILL from IOWA, MINN, MO, and SPP are lower than desired. These limitations are due to the Lakeshire-Watson and Meramec 3-Lemay Tap 1 138 kV lines. The area that encompasses these lines is currently under review by UE.

The following tabulation summarizes SCILL's emergency export capability.

Table 4B.13

1984 Emergency Transfer Capability - Export
ILLMO REGION - (SOUTH CENTRAL ILLINOIS)

<u>Export To</u>	<u>ETC (MW)</u>	<u>Limiting Facility</u>
CE	1800	Industrial Park-Meredosia 138 kV
ECAR	1600	Industrial Park-Meredosia 138 kV
IOWA	800	Maryville-St. Joseph 161 kV
MINN	350	Genoa-Lac Tap 161 kV
MO	1000	Cahokia 345/138 kV TRFR
SPP	1600(a)	Montgomery 345/161 kV TRFR
TVA	1600	Industrial Park-Meredosia 138 kV
WUMS	800	Electric Junction-Lombard 345 kV

- (a) SCILL to SPP emergency transfers are more restricted by the Montgomery-Montgomery Tap 161 kV line. This line is not listed because it is considered to be a local problem.

The ETC limits of SCILL are judged acceptable. However, SCILL's ETC to MINN is lower than desired.

During the 1979-1984 time period generation additions in Missouri (MO) include 2030 MW of base and 312 MW of peaking generation. Anticipated EHV line additions include several lines for new plant outlet capacity as well as a 500 kV UE-ASEC-MSUI tie in southeast Missouri. Proposed additional 345/138 kV and 345/161 kV transformation capabilities in MO amount to 1680 MVA and 2168 MVA, respectively, for this time period.

From the results of the study it appears that with presently planned generation and transmission additions, import capabilities under ETC criteria are adequate to meet MO's needs in 1984 except from the IOWA and MINN areas. Imports from these areas are limited by the facilities outside the MO area. Export capabilities under ETC criteria seem to be adequate except to the MINN and SCILL areas. Export to the MINN area is limited by a facility outside the MO area while export to SCILL area is limited by a 138 kV MO facility. Transmission in the area around the limiting facility is currently being studied by Union Electric.

The following tabulation summarizes MO's ETC.

Table 4B.14

1984 Emergency Transfer Capability - Import
ILLMO REGION - (MO AREA)

<u>Import From</u>	<u>ETC (MW)</u>	<u>Limiting Element</u>
CE	1100	Cahokia 345/138 kV Xfmr.
ECAR	1100	Cahokia 345/138 kV Xfmr.
IOWA	500	St. Joe 345/161 kV Xfmr.
MINN	450(a)	Alma-Wabco 161 kV
SCILL	1000	Cahokia 345/138 kV Xfmr.
SPP	2000	Cahokia 345/138 kV Xfmr.
TVA	1200	Cahokia 345/138 kV Xfmr.
WUMS	1300(b)	Cahokia 345/138 kV Xfmr.

- (a) MINN to MO transfers are limited to 250 MW by the T Corners-Wissota 115 kV line. However, this limiting element is considered to be a local problem and is, therefore, not listed.
- (b) WUMS to MO transfers are limited to 500 MW by the Waukegan-Kenosha 138 kV line. However, this limiting element is considered to be a local problem and is, therefore, not listed.

It can be seen that MO's import capability is limited from all the directions except IOWA and MINN by the Cahokia 345/138 kV Transformer #9. The limitation is based on the emergency rating of 560 MVA for this transformer for the sudden outage of Cahokia 345/138 kV Transformer #8 which requires a breaker to open at Cahokia in the Cahokia-Campbell-Roxford 345 kV line. Since both Cahokia transformers have a two hour emergency rating of 660 MVA, the Cahokia transformer limitation can be removed by switching at Cahokia which would reestablish the Cahokia-Campbell-Roxford 345 kV line within two hours. With the Cahokia transformer limitation removed, MO's import from all the directions will be limited by facilities outside the MO area.

The following tabulation summarizes MO's ETC.

Table 4B.15

1984 Emergency Transfer Capability - Export
ILLMO REGION (MO AREA)

<u>Export To</u>	<u>ETC (MW)</u>	<u>Limiting Element</u>
CE	1400	Dardenne-Pike 161 kV
ECAR	2700	Turkey Hill-New Memphis Tap 138 kV
IOWA	900(a)	Sycamore-Montezuma 345 kV
MINN	400	Genoa-LaCross Tap 161 kV
SCILL	550	Meramec 3-Lemay Tap 1 138 kV
SPP	1500(a)	Clark 138/161 kV Xfmr.
TVA	1900	Clark 138/161 kV Xfmr.
WUMS	800(b)	Electric Junction-Lombard 345 kV

(a) MO to IOWA transfers are limited to 400 MW by the Montgomery-Montgomery Tap 161 kV line. The same line limits MO to SPP transfers to zero MW. However, the emergency rating of this 0.2 mile long line is limited by terminal equipment, and hence it is considered a local problem, which is expected to be corrected.

(b) MO to WUMS transfers are limited to 400 MW by the T Corners-Wissota 115 kV line. However, this limiting element is considered to be a local problem and is, therefore, not listed.

The interregional transfer capabilities as determined from this study are as follows. These are approximate non-simultaneous values for emergency assistance above contracted schedules.

Table 4B.16

1984 MAIN Emergency Transfer Capability
ILLMO REGION

ECAR	to MAIN	3950	MW
MARCA	to MAIN	900	MW
SERC	to MAIN	4000+	MW
SPP	to MAIN	1100	MW
MAIN	to ECAR	3800	MW
MAIN	to MARCA	900	MW
MAIN	to SERC	1100	MW
MAIN	to SPP	1500	MW

Table 4B.17

List of Proposed Bulk Power Lines (1/1/80 to 1/1/90)
ILLMO REGION

Line Ownership List	Terminals	KM	Miles	Expected Service Date	Nominal Voltage In KV Oper Design	Notes	
01	02	03	04	05	06	07	08
UNEC	Cahokia-Roxford Tap-Campbell	3	2	5/80	345	345	Provide Area Protection
UNEC	Montgomery-Callaway 7	37	23	7/80	345	345	Increase Transfer Capability
UNEC	Montgomery-Callaway 8	37	23	10/81	345	345	Pre-Operational Power
UNEC	Callaway-Bland 1	48	30	10/81	345	345	Deliver Generator Output
UNEC	Mason-Sioux Tap-Belt	18	11	5/86	345	345	Deliver Generator Output
UNEC	Callaway-Bland 2	48	30	3/88	345	345	NRC- Separate Facility Require-
UNEC	Campbell-Belt	14	9	5/88	345	345	ment: Deliver Generator Output
ILPC	Maroa E.-Oreana	13.5	8.4	6/80	345	345	Relieve Overloads
ILPC	Clinton-Brokaw	36.2	22.5	6/81	345	345	Deliver Generator Output
ILPC	Clinton-Maroa E.	20.1	12.5	6/81	345	345	Deliver Generator Output
ILPC	Clinton-Maroa W.	20.1	12.5	6/81	345	345	Deliver Generator Output
ILPC	W. Kansas-Sidney	57.1	35.5	6/83	345	345	Relieve Overloads
CEIL	Duck Creek-Fargo	53	33	12/85	345	345	Relieve Overloads
CEIP	Sidney-Paxton	61	38	3/86	345	345	Provide Area Protection
ILPC	Maroa W.-Oreana	13.5	8.4	6/86	345	345	Relieve Overloads
WEIL	Pawnee-Rees Station	50	31	6/87	345	345	Relieve Overloads

Table 4B.18

Historical Capability (MW) and Reserves (MW and Percent)
ILLMO REGION

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	13,547	14,063	14,643	14,891	15,012	14,919
2. Peak Demand	11,698	9,110	11,549	9,286	12,091	8,981
3. Planned Reserves (1-2)	1,849	4,953	3,094	5,605	2,921	5,938
4. Planned Reserves (%) (3÷2) x 100%	15.8	54.4	26.8	60.4	24.2	66.1
5. Net Transactions (Imports-Exports)	1,729	-941	-499	192	274	-304
6. Total Capability (1+5)	15,276	13,122	14,144	15,083	15,286	14,615
7. Total Reserves (6-2)	3,578	4,012	2,595	5,797	3,195	5,634
8. Total Reserves (%) (7÷2) x 100%	30.6	44.0	22.5	62.4	26.4	62.7
9. Scheduled Maintenance	33	761	706	1,427	40	1,858
10. Capability after Maintenance (6-9)	15,243	12,361	13,438	13,656	15,246	12,757
11. Reserves after Maintenance (10-2)	3,545	3,251	1,889	4,370	3,155	3,776
12. Reserves after Maintenance (%) (11÷2) x 100%	30.3	35.7	16.4	47.1	26.1	42.0
13. Inoperable Capability 1/	0	0	0	0	0	0
14. Available Capability (10-13)	15,243	12,361	13,438	13,656	15,246	12,757
15. Available Reserves (14-2)	3,545	3,251	1,889	4,370	3,155	3,776
16. Available Reserves (%) (15÷2) x 100%	30.3	35.7	16.4	47.1	26.1	42.0
17. Forced Outages	2,130	1,776	903	3,056	1,975	1,452
18. Actual Capability after Forced Outages (14-17)	13,113	10,585	12,535	10,600	13,271	11,305
19. Actual Reserves (18-2)	1,415	1,475	986	1,314	1,180	2,324
20. Actual Reserves (%) (19÷2) x 100%	12.1	16.2	8.5	14.2	9.8	25.9

1/ Included in Item 17

Table 4B.19

Current Capability (MW) and Reserves (MW and Percent)
ILLMO REGION

	1980	
	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	15,623	15,626
2. Peak Demand	12,596	10,086
3. Planned Reserves (1-2)	3,027	5,540
4. Planned Reserves (%) (3÷2) x 100%	24.0	54.9
5. Net Transactions (Imports-Exports)	137	-441
6. Total Capability (1+5)	15,760	15,185
7. Total Reserves (6-2)	3,164	5,099
8. Total Reserves (%) (7÷2) x 100%	25.1	50.6
9. Scheduled Maintenance	0	1,667
10. Capability after Maintenance (6-9)	15,760	13,518
11. Reserves after Maintenance (10-2)	3,164	3,432
12. Reserves after Maintenance (%) (11÷2) x 100%	25.1	34.0
13. Inoperable Capability	35	37
14. Available Capability (10-13)	15,725	13,481
15. Available Reserves (14-2)	3,129	3,395
16. Available Reserves (%) (15÷2) x 100%	24.8	33.7
17. Forced Outages <u>1/</u>	0	0
18. Actual Capability after Forced Outages (14-17)	15,725	13,481
19. Actual Reserves (18-2)	3,129	3,395
20. Actual Reserves (%) (19÷2) x 100%	24.8	33.7

1/ No information supplied.

Table 4B.20

Future Capability (MW) and Reserves (MW and Percent)
ILLMO REGION

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	15764	15806	15922	18708	18658	18713	18618	18678	18607	18664
2. Peak Demand	13039	10541	13468	11173	13863	11584	14308	12126	14750	12719
3. Planned Reserves (1-2)	2725	5265	2454	7535	4795	7134	4310	6552	3857	5945
4. Planned Reserves(%)(3+2)x100%	20.9	49.9	18.2	67.4	34.6	61.5	30.1	54.0	26.1	46.7
5. Net Transactions (Imports-Exports)	170	-761	113	-461	-184	-761	-181	-625	-178	-761
6. Total Capability (1+5)	15934	15045	16035	18247	18474	17957	18437	18053	18429	17903
7. Total Reserves (6-2)	2895	4504	2567	7074	4611	6373	4129	5927	3679	5184
8. Total Reserves (%)(7+2)x100%	22.2	42.7	19.1	63.3	33.3	55.0	28.9	48.9	24.9	40.8
9. Scheduled Maintenance	0	1421	0	1372	0	1214	0	1214	0	0
10. Capability after Maintenance (6-9)	15934	13624	16035	16875	18474	16743	18437	16839	18429	17903
11. Reserves after Maintenance (10-2)	2895	3083	2567	5702	4611	5159	4129	4713	3679	5184
12. Reserves after Maintenance(%)(11+2)x100%	22.2	29.2	19.1	51.0	33.3	44.5	28.9	38.9	24.9	40.8
13. Inoperable Capability	35	37	35	37	35	0	0	0	0	0
14. Available Capability (10-13)	15899	13587	16000	16838	18439	16743	18437	16839	18429	17903
15. Available Reserves (14-2)	2860	3046	2532	5665	4576	5159	4129	4713	3679	5184
16. Available Reserves(%)(15+2)x100%	21.9	28.9	18.8	50.7	33.0	44.5	28.9	38.9	24.9	40.8
17. Forced Outages <u>1/</u>	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages(14-17)	15899	13587	16000	16838	18439	16743	18437	16839	18429	17903
19. Actual Reserves (18-2)	2860	3046	2532	5665	4576	5159	4129	4713	3679	5184
20. Actual Reserves (%)(19+2)x 100%	21.9	28.9	18.8	50.7	33.0	44.5	28.9	38.9	24.9	40.8

1/ No information supplied.

Table 4B.21

Future Capability (MW) and Reserves (MW and Percent)
ILLMO REGION

	1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	19704	19161	19541	19598	20816	21223	21021	21078
2. Peak Demand	15805	13284	15713	13934	16194	14570	16667	15198
3. Planned Reserves (1-2)	3899	5877	3828	5664	4622	6653	4354	5880
4. Planned Reserves (%) (3+2) x100%	25.6	44.2	24.4	40.6	28.5	45.7	26.1	38.7
5. Net Transactions (Imports-Exports)	-205	-791	-204	-791	-199	-791	-196	-887
6. Total Capability (1+5)	18899	18370	19337	18807	20617	20432	20825	20191
7. Total Reserves (6-2)	3694	5086	3624	4873	4423	5862	4158	4993
8. Total Reserves (%) (7+2) x100%	24.3	38.3	23.1	35.0	27.3	40.2	24.9	32.9
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	18899	18370	19337	18807	20617	20432	20825	20191
11. Reserves after Maintenance (10-2)	3694	5086	3624	4873	4423	5862	4158	4993
12. Reserves after Maintenance (%) (11+2) x 100%	24.3	38.3	23.1	35.0	27.3	40.2	24.9	32.9
13. Inoperable Capability 1/	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	18899	18370	19337	18807	20617	20432	20825	20191
15. Available Reserves (14-2)	3694	5086	3624	4873	4423	5862	4158	4993
16. Available Reserves (%) (15+2) x 100%	24.3	38.3	23.1	35.0	27.3	40.2	24.9	32.9
17. Forced Outages 1/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	18899	18370	19337	18807	20617	20432	20825	20191
19. Actual Reserves (18-2)	3694	5086	3624	4873	4423	5862	4158	4993
20. Actual Reserves (%) (19+2) x 100%	24.3	38.3	23.1	35.0	27.3	40.2	24.9	32.9

1/ No information supplied

Table 4B.22

Planned Capability as of January 1 by Type of Fuel - MW
ILLMO REGION

Summer Capability

	Nuclear Steam	Coal Steam	OIL			NATURAL GAS			HYDRO		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convrt.	Pumped Storage	
1980	-----	13041	1010	765	38	57	79	--	333	300	15623
% TOTAL	-----	83.5	6.5	4.9	0.2	0.4	0.5	--	2.1	1.9	100.0
1981	-----	13041	995	765	38	36	79	--	333	300	15587
% TOTAL	-----	83.7	6.4	4.9	0.3	0.2	0.5	--	2.1	1.9	100.0
1982	-----	13101	995	867	38	36	79	--	333	300	15749
% TOTAL	-----	83.2	6.3	5.5	0.3	0.2	0.5	--	2.1	1.9	100.0
1983	2098	13834	940	867	38	36	79	--	333	300	18525
% TOTAL	11.3	74.7	5.1	4.7	0.2	0.2	0.4	--	1.8	1.6	100.0
1984	2098	13952	940	867	38	36	79	--	333	300	18613
% TOTAL	11.3	74.8	5.0	4.7	0.2	0.2	0.4	--	1.8	1.6	100.0
1985	2098	13922	905	892	38	36	79	--	333	300	18603
% TOTAL	11.3	74.8	4.9	4.8	0.2	0.2	0.4	--	1.8	1.6	100.0
1986	2098	13911	905	892	38	36	79	--	333	300	18592
% TOTAL	11.3	74.8	4.9	4.8	0.2	0.2	0.4	--	1.8	1.6	100.0
1987	2098	14311	905	989	38	36	79	--	333	300	19089
% TOTAL	11.0	75.0	4.7	5.2	0.2	0.2	0.4	--	1.7	1.6	100.0
1988	2098	14747	905	989	38	36	79	--	333	300	19525
% TOTAL	10.8	75.5	4.6	5.1	0.2	0.2	0.4	--	1.7	1.5	100.0
1989	3248	15197	905	1014	38	36	79	--	333	300	21150
% TOTAL	15.3	71.8	4.3	4.8	0.2	0.2	0.4	--	1.6	1.4	100.0

Table 4B.23

Major Future Generating Capability (Installations and Removals)
ILLMO REGION

<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type</u>	<u>Net Summer Capability (MW)</u>	<u>Effective Date</u>	
					<u>ERA 411, 1980</u>	<u>ERA 383 1979</u>
Union EL Co.	Peaking	GT	FO2	102	5/81	5/80
Union El.Co.	Meramac	ST	BIT	158	5/82	10/82
Union El.Co.	Callaway #1	NP	UR	1150	10/82	10/82
Cent.II.Pub.Ser.	Newton #2	ST	COL	575	12/82	12/81
Il.Power Co.	Clinton #1	NB	UR	760	12/82	12/82
Soyland Coop.	Clinton #1	NB	UR	100	12/82	12/82
Western Il.Pwr.Coop.	Clinton #1	NB	UR	88	12/82	12/82
Cent.II.Light Co.	Duck Creek #2	ST	COL	400	3/86	3/84
Soyland Coop.	Undetermined	ST	COL	450	5/87	5/87
Union El.Co.	Callaway #2	NP	UR	1150	4/88	4/87
Southern Il.Pwr.Coop.	Marion #5	ST	COL	350	9/88	6/88
Il.Power Co.	Clinton #2	NB	UR	760	*	6/88
Western Il.Pwr.Coop.	Undetermined	ST	COL	100	9/88	*
Cent.II.Lt.Co.	Wallace 3-6,7	ST	COL	(145)	6/89	*

* Unit Not Reported

ELECTRIC REGION 19
Wisconsin-Upper Michigan Systems Group (WUMS)

Historical Perspective

Electric Region 19 (ER19-WUMS) includes the eastern portion of Wisconsin and all of Upper Michigan except for the small portion at the eastern end which is in the ECAR region. The major power suppliers in the region are the Wisconsin Electric Power Co., Wisconsin Power and Light Co., Wisconsin Public Service Corp., and Madison Gas and Electric Co. Collectively, the four companies own about 88% of the total capacity in the region and serve 1.44 million customers, of which 1.40 million are residential customers, about 17,000 are farm customers, 137,000 are commercial customers, and 1300 are industrial customers. These electric systems are interconnected with 345 kV ties as well as at lower voltages. The systems also have 345 kV ties with the Commonwealth Electric Co. (ER6-CECO) and with Northern States Power Co. in the MARCA region.

The above companies, except for the Wisconsin Electric Power Co., are members of a formal power pool-the Wisconsin Power Pool (WIPP). The participants in the WIPP coordinate their planning and installation of generating and transmission facilities and the operation of their systems, including emergency and economy exchanges, spinning reserves and maintenance schedule.

The WIPP systems are also members of the Wisconsin-Upper Michigan Systems (WUMS). In addition to the three WIPP members, the Wisconsin Electric Power Co., and the Upper Peninsula Power Co., are participants in WUMS. Differentiating the two groups, WUMS is primarily concerned with the reliability and adequacy of power supply of its members, whereas WIPP primarily is concerned with the economy of supply for its members. WIPP members have constructed several joint power projects to achieve their objectives.

All of the members of WUMS are also members of the MAIN organization and WUMS is a major subgroup of MAIN. Other systems located geographically within the WUMS region which report to MAIN are: Kaukauna, WI., Manitowoc, WI., Marshfield, WI., and Marquette, MI. Data for these for systems are included in this report for WUMS.

WUMS has historically been a summer-peaking region. Table 4C.1 shows the region's summer and winter peaks for the period 1977-1979.

Table 4C.1
Historical Peak Demand-MW
WUMS Region

	<u>Summer</u>			<u>Winter</u>		
	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	5847	6499	5731	5843	6011	5680
1978	6155	<u>6173</u>	6450	6067	<u>6266</u>	6092
1979	5931	6289	<u>6510</u>	6238	<u>6310</u>	6047

Underline indicates seasonal peak.

The summer peak demands are dependent on climatic conditions and are temperature/humidity sensitive. Usually the peak will occur in July or August.

The winter peak usually occurs in January, but it may occur in any winter month, depending on the combination of weather and economic activity in the region. The winter peak during the 1977-79 period was 3-8% less than the corresponding summer peak.

Table 4C.2 shows the scheduled maintenance performed each period and also the capability unavailable due to forced outages or otherwise inoperable

Table 4C.2
Scheduled Maintenance and Unavailable Capabilities
WUMS Region

	<u>Summer</u>			<u>Winter</u>		
	<u>Sched- uled Maint- enance (MW)</u>	<u>Other Un- avail- able (MW)</u>	<u>Total Un- avail- able (MW)</u>	<u>Sched- uled Maint- enance (MW)</u>	<u>Other Un- avail- able (MW)</u>	<u>Total Un- avail- able (MW)</u>
1977	223	272	495	504	467	971
1978	211	341	552	648	508	1156
1979	168	1281	1449	596	911	1506

The capability unavailable for reasons other than scheduled maintenance varied from 4-15% of the installed capability in summer and from 6-11% in winter.

The reserve margins for the 1977-79 seasonal periods are shown below, considering the effects of scheduled maintenance and other outages.

Table 4C.3
Historical Seasonal Reserve
WUMS Region

<u>S U M M E R</u>							
	<u>Peak</u> <u>Demand</u> <u>(MW)</u>	<u>Total</u> <u>Capa-</u> <u>bility</u> <u>(MW)</u>	<u>Total</u> <u>Reserves</u> <u>(%)</u>	<u>Avail-</u> <u>able</u> <u>Capa-</u> <u>bility</u> <u>(MW)</u>	<u>Avail-</u> <u>able</u> <u>Reserves</u> <u>(%)</u>	<u>Actual</u> <u>Capa-</u> <u>bility</u> <u>(MW)</u>	<u>Actual</u> <u>Reserves</u> <u>(%)</u>
1977	6499	7711	18.6	7488	15.2	7216	11.0
1978	6450	8218	27.4	8007	24.1	7666	18.9
1979	6510	8844	35.9	8676	33.3	7395	13.6
<u>W I N T E R</u>							
1977	6011	7821	30.1	7317	21.7	6850	14.0
1978	6266	8554	36.5	7906	26.2	7398	18.1
1979	6310	8833	40.0	8237	30.5	7326	16.1

The reserve margins shown above indicate that for the 1977-79 period sufficient capability was available to meet the demand requirements in both the summer and winter periods, after taking into account both scheduled and forced outages, and still have ample actual reserves to meet other contingencies. However, the reserves are somewhat larger than usually planned. This was caused by less growth in the peak demands than typically would be expected.

Table 4C.4 shows the energy requirements, summer and winter demands, and annual load factors for the 1977-79 period.

Table 4C.4
Historical Energy Peaks and Load Factors
WUMS Region

	Energy Requirement (GWh) (Growth %)		Summer Demand (MW) (Growth %)		Winter Demand (MW) (Growth %)		Annual Load Factor (%)
1977	34601	-	6499	-	6011	-	60.8
1978	37128	7.3	6450	(0.8)	6266	4.2	65.7
1979	38398	3.4	6510	0.9	6310	0.7	67.3
% Growth 1977-79		5.3		0.1		2.5	

Over the period, the energy requirements grew at a compound growth rate of 5.3%. This is considerably greater than the other regions in MAIN. The summer and winter demands show little growth during the period, which is consistent with the other MAIN regions. The lesser rate of the growth of the demands with respect to the energy resulted in higher than usual annual load factors.

Current Perspective

The projected summer and winter demands are shown below.

Table 4C.5
Projected 1980 Seasonal Peak Demand*-MW
WUMS Region

Summer			Winter		
<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
6466	6778	6863	6743	6875	6548

* Coincident as to month.

The 1980 summer and winter demands are projected to occur in August and January, respectively. This is consistent with previous occurrences. However, the peak may occur in any month of the seasons depending on economic and climatic conditions.

The monthly coincident winter peak is slightly greater than the summer monthly coincident peak. However, the summer and winter non-coincident peaks are 6915 MW and 6878 MW, respectively. On this basis, the region would still be summer peaking in 1980. Long range projections indicate that the region will probably shift to winter peaking.

The 1980 summer planned capability of WUMS is estimated to be 9018 MW and the non-consistent summer peak demand is projected to be 6915 MW, resulting in planned reserves of 2103 MW or 30.4%. After adjustment for scheduled receipts and deliveries, the total reserves are slightly increased to 2121 MW or 30.7%; and after adjustment for scheduled unavailable capacity during the summer peak period, the operating reserves are projected to be 30.1%.

The summer and winter 1980 reserve margins for the electric region are shown below.

Table 4C.6

Reserve Margins *
WUMS Region

<u>S U M M E R</u>			<u>W I N T E R</u>		
<u>Planned</u> <u>Reserves</u> <u>(MW) (%)</u>	<u>Total</u> <u>Reserves</u> <u>(MW) (%)</u>	<u>Avail-</u> <u>able</u> <u>Reserves</u> <u>(MW) (%)</u>	<u>Planned</u> <u>Reserves</u> <u>(MW) (%)</u>	<u>Total</u> <u>Reserves</u> <u>(MW) (%)</u>	<u>Avail-</u> <u>able</u> <u>Reserves</u> <u>(MW) (%)</u>
2103 30.4	2121 30.7	2083 30.1	2382 34.6	2405 35.0	2073 30.1

* Based on ERA Form 411

The margins shown above have not been adjusted for unscheduled outages of capacity as the amount of these outages are unknown ahead of time. If these outages do not exceed the maximum outages of the 1977-79 period, 15% of installed capacity during the summer period and 10% during the winter, the resultant available reserves of 730 MW, 8.1% and 1054 MW, 11.4%, respectively, would be in excess of peak requirements.

Almost two-thirds of the current capacity is coal-fired steam capacity; 4%, oil-fired steam; and 9%, oil-fired combustion turbine capacity. There are 3 nuclear units installed in WUMS with Westinghouse reactors comprising 18% of the total capability. A 580 MW coal-fired steam unit is scheduled for service in July 1980. If this unit is delayed beyond the start of the summer peak period, the operating reserves would be reduced to 21.7%. This is still within the required minimum reserve limit. There are no new nuclear plants planned for service in 1980.

The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown below.

Table 4C.8
1980 Requirements
WUMS Region

	<u>Energy Requirement</u>	<u>Summer Demand</u>	<u>Winter Demand</u>	<u>Annual L.F.</u>
	(GWH)	(MW)	(MW)	(%)
	40487	6915	6878	66.7
% Growth 1980/79	5.4	6.2	9.0	

The 1980 projected summer and winter demands are projected to grow at considerably higher rates than they did during the 1977-79 period - 0.1% and 2.5%, respectively.

This is due in part to the result of the previous forecast overestimating the 1979 summer peak and also the 1979/80 winter peak. Although the peaks and energy are forecasted to grow at a faster rate than during the 1977-79 periods, the projected 1980 values are considerably below those which were projected last year for the corresponding period.

The projected 1980 energy requirement growth rate of 5.4% over 1979 requirement is in line with the historic 1977-79 rate of 5.3%.

The projected 1980 annual load factor, 66.7%, is about normal for the region, which has large mining loads in the northern portion.

Delays of future critical bulk power transmission facilities that will not be in service when needed are required to be reported under Item 5-C of the ERA 411 report. In the April 1, 1980, MAIN report, no delays are reported for the WUMS region.

Future Perspective.

The range of total reserves for the WUMS region for the periods 1981-85 and 1986-89 are tabulated below.

Table 4C.9

Range of Total Reserves - %
WUMS Region

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
27.5 - 31.6	27.3 - 31.7	18.7 - 28.0	14.2 - 25.8

As seen above, the projected summer reserve exceeds the 15% MAIN minimum reserve margin criteria for all the years in each time period. However, the winter reserve margin drops below the 15% requirement in 1988 and 1989. An additional 61 MW and 77 MW are needed to bring it up to that level. It is expected that arrangements will be made to purchase the capacity from the excess available in MAIN if this is required. A 225 MW reserve capacity purchase from Commonwealth Edison Co. was contracted for 1986 when it was first forecasted that reserve requirements would be deficient in that year. However, the latest figures indicate that this is not necessary.

Projected growth rates of demand and energy for each period and the overall rates for 1981-1989 are shown below.

Table 4C.10

Projected Energy and Demand Growth Rate
WUMS Region

	<u>Energy Requirements</u>		<u>Summer Demand</u>		<u>Winter Demand</u>		<u>Annual Load</u>
		<u>Growth</u>		<u>Growth</u>		<u>Growth</u>	<u>Factor</u>
	<u>(GWh)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(MW)</u>	<u>(%)</u>	<u>(%)</u>
1981	41278	2.0	7103	2.7	7124	3.3	66.1
1982	42526	3.0	7291	2.6	7357	3.4	66.0
1983	43696	2.8	7475	2.5	7606	3.4	65.6
1984	44910	2.8	7652	2.4	7852	3.2	65.1
1985	46144	2.7	7855	2.7	8127	3.5	64.8
% Growth							
81-85		<u>2.8</u>		<u>2.5</u>		<u>3.3</u>	
1986	47526	3.0	8068	2.7	8405	3.4	64.5
1987	48949	3.0	8297	2.8	8697	3.5	64.2
1988	50319	2.8	8514	2.6	9042	4.0	63.4
1989	52120	3.6	8787	3.2	9352	3.4	63.6
% Growth							
86-89		<u>3.1</u>		<u>2.9</u>		<u>3.6</u>	
% Growth							
81-89		<u>3.0</u>		<u>2.7</u>		<u>3.5</u>	

The 1981-1985 summer demands are projected to grow at a compound rate of 2.5%; 1986-1989, 2.9%; and overall, 1981-1989, at 2.7%. These rates appear reasonable and in line with rates projected for other regions in the MAIN region.

The winter demand growth rates are projected to increase to 3.3% for the 1981-85 period and to 3.6% for the 1986-89 period with an overall 1981-89 rate of 3.5%.

The ratio between the winter and summer peaks is projected to change from 96.9% in 1979, to 103.5% in 1985, to 106.4% in 1989, which means the region is projected to change from a summer peaking region to a winter peaking region. The energy requirements are projected to grow 2.8% from 1981-85; 3.1% from 1986-1989; and 3.0% for the overall period 1981-1989. Historically, 1977-79, the energy grew 5.3%. The projected 1981-89 energy requirements for the region are comparable to projections of other regions in MAIN for the period.

The summer capability of units installed in the region for the period 1980-1989 is shown by type of fuel in Table 4C.18. Major generating unit additions during the period are given in Table 4C.19. The percentages of each type of capability for the target years 1980, 1984, and 1989 are given below.

Table 4C.11

Installed Generating Capability by Type of Fuel - %
WUMS Region

Summer Capability

	Nuclear	Coal	Oil			Natural Gas		Hydro			Total
	Steam	Steam	ST	CT	IC	ST	CT	IC	Conv.	P.S.	Capability
1980	17.9	65.1	4.0	9.3	0.6	0.1	0.2	-	2.8	-	100.0
1984	15.7	72.3	0.7	8.1	0.5	0.1	0.2	-	2.4	-	100.0
1989	15.1	73.3	0.6	8.0	0.4	0.1	0.2	-	2.3	-	100.0

Currently, coal is the primary fuel for about 65% of the planned capability of the region. This percentage is projected to increase to 72% by 1984 and to 73% by 1989, due to the installation of the Wisconsin Electric Power 580 MW Pleasant Prairie No. 1 coal unit in July, 1980; the Weston No. 3 320 MW coal unit of Wisconsin Public Service in March, 1982; the 580 MW Pleasant Prairie No. 2 coal unit of Wisconsin Electric in April 1983; and the joint 400 MW Edgewater No. 5 unit of Wisconsin Electric and Wisconsin Public Service scheduled for April 1984. If the inservice date of the 1982 unit is delayed beyond the start of the summer 1982 peak period, the available reserve would be reduced from 25.9% to 21.5%, which is still greater than the planned reserve requirements. A delay in the 1983 and 1984 unit would reduce the actual reserve in those years to 20.7% and 25.1%, respectively. These are also greater than the planned reserve requirements.

Oil-fired steam generating units comprise only 4% of the 1980 capability and consists of 336 MW. This is scheduled to decrease to 67 MW by 1984 and to 61 MW by 1985, and to remain at that level through 1989.

The adequacy and reliability of the region's transmission network is tested periodically for contingency conditions in accordance with MAIN Guide No. 12. The results of the investigation of the 1984 Emergency Transfer Capabilities (ETC's) for the WUMS area follow:

The 1984 model used to represent WUMS in this study incorporates the addition of 1860 MW of new generating capacity between 1979 and 1984 inclusive. This additional capacity will be located at Pleasant Prairie, Weston, and Edgewater.

WUMS Emergency Transfer Capability (ETC), as determined by this study, illustrates a decrease from the levels of previous Future System Studies, as tabulated here.

Table 4C.12

Emergency Transfer Capability - MW
WUMS Region

<u>From/Year</u>	<u>1980(1)</u>	<u>1982(2)</u>	<u>1984</u>
CE	1600	1000	900
IOWA	1500	1000	800
MINN	1100	750	600
MO	1600	1000	800
SCILL	1700	1000	800

- (1) This data was taken from the 1980 Interchange Capability Study that was published in November 1975.
- (2) This data was taken from the 1982 Interchange Capability Study that was published in September 1977.

The reduction in the MINN-WUMS interchange level is a matter of concern and will be considered when evaluating future system additions. The values reported above for 1984, however, are considered adequate.

The import capability for WUMS is described below.

The non-simultaneous Emergency Transfer Capability (ETC) from CE is 900 MW for loss of the Lockport to Lisle 345 kV line with the Electric Junction to Lombard 345 kV line as the limiting element.

The Electric Junction to Lombard 345 kV line limits the ETC from IOWA to 800 MW for loss of the Lockport to Lisle 345 kV line.

The ETC from MINN is limited to 600 MW by the Alma to Wabaco 161 kV line with the Adams to Zumbrota 345 kV line out.

The Electric Junction to Lombard 345 kV line is the limiting element for a loss of the Lockport to Lisle 345 kV line for the ETC imports from MO. The interchange limits are 800 MW for the ETC.

The ETC from SCILL is limited to 800 MW for an outage of the Lockport-Lisle 345 kV line with the Electric Junction to Lombard 345 kV line being the limiting element.

The export capabilities for WUMS are described below.

The ETC to CE is 1200 MW with the Zion to Pleasant Prairie 345 kV line as the limiting element for loss of the Zion to Arcadian 345 kV line.

The Sycamore to Montezuma 345 kV line limits the ETC to IOWA to 800 MW for loss of the Cooper to Booneville 345 kV line.

The outage of the LaCrosse to Genoa 161 kV line limits the ETC to MINN to 500 MW with the Genmoa to LaCrosse tap as the limiting element.

The WUMS exports to MO are limited to 1300 MW for the ETC with the Cahokia 345/138 kV transformer as the limiting element for the double outage of the other Cahokia 345/138 kV transformer and the Cahokia to Campbell 345 kV line.

The ETC to SCILL is limited to 1300 MW by the Zion to Pleasant Prairie 345 kV line when the Zion to Arcadian 345 kV line is out of service.

The interregional transfer capabilities as determined from this study are as follow. These are approximate non-simultaneous values above contracted schedules, based on emergency transfer capabilities.

Table 4C.13
1984 MAIN Emergency Transfer Capability - MW
WUMS Region

ECAR	to MAIN	2900 MW
MARCA	to MAIN	800 MW
SERC	to MAIN	2800 MW
SPP	to MAIN	1900 MW
MAIN	to ECAR	4000+MW
MAIN	to MARCA	550 MW
MAIN	to SERC	3200 MW
MAIN	to SPP	1800 MW

Table 4C.14 lists proposed bulk power lines. Many of these lines are required to provide area protection, and increase transfer capability.

Table 4C.14

List of Proposed Bulk Power Lines
1/1/80 to 1/1/90

WUMS Region

Line Ownership List	Terminals	Line Length		Planned Service Date	Nominal Voltage in KV		Remarks
		KM	MI		Oper	Dsgn	
WIEP	Pleasant Prairie-Arcadian	87	54	4/82	345	345	Deliver Generator Output
WIPS	Black Brook-Venus	51	32	8/82	115	345	Relieve Overloads
WIPL	Paddock-Paddock Tap	.6	.4	6/83	345	345	Provide Area Protection
WIPL	Paddock-Paddock Tap	.6	.4	6/83	345	345	Provide Area Protection
MAGE	N. Madison - S. Madison	58	36	6/85	345	345	Provide Area Protection
WIEP	Brookdale-Granville	23	14	6/86	345	345	Provide Area Protection
WIEP	Brookdale-Racine	50	31	6/86	345	345	Provide Area Protection
WIPL	South Madison - Paddock	64	40	6/86	345	345	Provide Area Protection
WIPL/CECO	Paddock-Wempletown	8	5	7/86	345	345	Increase Transfer Capability Miles Shown for WIPL Portion
WIEP/WIPS	Venus-Plains	103	64	6/87	345	345	Provide Area Protection
WIEP	Wesbay-Existing	43	27	6/87	345	345	Provide Area Protection
WIPS	Wesbay-Existing	11	7	6/87	345	345	Provide Area Protection

Note: WUMS = WIEP + WIPS + WIPL

Table 4C.15

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Wisconsin - Upper Michigan Systems Group - WUMS

	1977		1978		1979	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	7419	7563	8099	8403	8295	8630
2. Peak Demand	6499	6011	6450	6266	6510	6310
3. Planned Reserves (1-2)	920	1552	1649	2137	1785	2320
4. Planned Reserves (%) (3/2)x100	14.2	25.8	25.6	34.1	27.4	36.8
5. Net Transactions (Imports-Exports)	292	258	119	151	549	203
6. Total Capability (1+5)	7711	7821	8218	8554	8844	8833
7. Total Reserves (6-2)	1212	1810	1768	2288	2334	2523
8. Total Reserves (%) (7/2)x100	18.6	30.1	27.4	36.5	35.9	40.0
9. Scheduled Maintenance	223	504	211	648	168	596
10. Capability after Maintenance (6-9)	7488	7317	8007	7906	8676	8237
11. Reserves after Maintenance (10-2)	989	1306	1557	1640	2166	1927
12. Reserves after Maintenance (%) (11/2)x100	15.2	21.7	24.1	26.2	33.3	30.5
13. Inoperable Capability	272	467	341	508	1281	911
14. Available Capability (10-13)	7216	6850	7666	7398	7395	7326
15. Available Reserves (14-2)	717	839	1216	1132	885	1016
16. Available Reserves (%) (15/2)x100	11.0	14.0	18.9	18.1	13.6	16.1
17. Forced Outages <u>1/</u>	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	7216	6850	7666	7398	7395	7326
19. Actual Reserves (18-2)	717	839	1216	1132	885	1016
20. Actual Reserves (%) (19/2)x100	11.0	14.0	18.9	18.1	13.6	16.1

1/ Information not reported separately.

Table 4C.16

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Wisconsin - Upper Michigan Systems Group - WUMS

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	9018	9260
2. Peak Demand	6915	6876
3. Planned Reserves (1-2)	2103	2384
4. Planned Reserves (%) (3/2)x100	30.4	34.7
5. Net Transactions (Imports-Exports)	18	23
6. Total Capability (1+5)	9036	9283
7. Total Reserves (6-2)	2121	2407
8. Total Reserves (%) (7/2)x100	30.7	35.0
9. Scheduled Maintenance	0	332
10. Capability after Maintenance (6-9)	9036	8951
11. Reserves after Maintenance (10-2)	2121	2075
12. Reserves after Maintenance (%) (11/2)x100	30.7	30.2
13. Inoperable Capability	38	0
14. Available Capability (10-13)	8998	8951
15. Available Reserves (14-2)	2083	2075
16. Available Reserves (%) (15/2)x100	30.1	30.2
17. Forced Outages <u>2/</u>	0	0
18. Actual Capability after Forced Outages (14-17)	8998	8951
19. Actual Reserves (18-2)	2083	2075
20. Actual Reserves (%) (19/2)x100	30.1	30.2

1/ No delays are anticipated in new generating units since submittal of 1980 ERA-411

2/ Information not reported separately.

Table 4C.17.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Wisconsin - Upper Michigan Systems Group - WUMS

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	9031	9260	9331	9592	9650	9876	10044	10304
2. Peak Demand	7103	7124	7291	7357	7475	7606	7652	7852
3. Planned Reserves (1-2)	1928	2136	2040	2235	2175	2270	2392	2452
4. Planned Reserves (%) (3/2)x100	27.1	30.0	28.0	30.4	29.1	29.8	31.3	31.2
5. Net Transactions (Imports-Exports)	22	27	25	31	28	34	27	36
6. Total Capability (1+5)	9053	9287	9356	9623	9678	9910	10071	10340
7. Total Reserves (6-2)	1950	2163	2065	2266	2203	2304	2419	2488
8. Total Reserves (%) (7/2)x100	27.5	30.4	28.3	30.8	29.5	30.3	31.6	31.7
9. Scheduled Maintenance	112	282	175	406	74	398	95	384
10. Capability after Maintenance (6-9)	8941	9005	9181	9217	9604	9512	9976	9956
11. Reserves after Maintenance (10-2)	1838	1881	1890	1860	2129	1906	2324	2104
12. Reserves after Maintenance (%) (11/2)x100	25.9	26.4	25.9	25.3	28.5	25.1	30.4	26.8
13. Inoperable Capability <u>1/</u>	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	8941	9005	9181	9217	9604	9512	9976	9956
15. Available Reserves (14-2)	1838	1881	1890	1860	2129	1906	2324	2104
16. Available Reserves (%) (15/2)x100	25.9	26.4	25.9	25.3	28.5	25.1	30.4	26.8
17. Forced Outages <u>1/</u>	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	8941	9005	9181	9217	9604	9512	9976	9956
19. Actual Reserves (18-2)	1838	1881	1890	1860	2129	1906	2324	2104
20. Actual Reserves (%) (19/2)x100	25.9	26.4	25.9	25.3	28.5	25.1	30.4	26.8

1/ Information not available.

Table 4C.17.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
 Wisconsin - Upper Michigan Systems Group - WUMS

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	10070	10304	10070	10304	10070	10304	10060	10282	10450	10682
2. Peak Demand	7855	8127	8068	8405	8297	8679	8514	9042	8787	9352
3. Planned Reserves (1-2)	2215	2177	2002	1899	1773	1607	1546	1240	1663	1330
4. Planned Reserves (%) (3/2)x100	28.2	26.8	24.8	22.6	21.4	18.5	18.2	13.7	18.9	14.2
5. Net Transactions (Imports-Exports)	14	40	258	270	37	50	42	55	46	50
6. Total Capability (1+5)	10084	10344	10328	10574	10107	10354	10102	10337	10496	10732
7. Total Reserves (6-2)	2229	2217	2260	2169	1810	1657	1588	1295	1709	1380
8. Total Reserves (%) (7/2)x100	28.4	27.3	28.0	25.8	21.8	19.1	18.7	14.3	19.4	14.8
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	10084	10344	10328	10574	10107	10354	10102	10337	10496	10732
11. Reserves after Maintenance (10-2)	2229	2217	2260	2169	1810	1657	1588	1295	1709	1380
12. Reserves after Maintenance (%) (11/2)x100	28.4	27.3	28.0	25.8	21.8	19.1	18.7	14.3	19.4	14.8
13. Inoperable Capability 1/	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	10084	10344	10328	10574	10107	10354	10102	10337	10496	10732
15. Available Reserves (14-2)	2229	2217	2260	2169	1810	1657	1588	1295	1709	1380
16. Available Reserves (%) (15/2)x100	28.4	27.3	28.0	25.8	21.8	19.1	18.7	14.3	19.4	14.8
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	10084	10344	10328	10574	10107	10354	10102	10337	10496	10732
19. Actual Reserves (18-2)	2229	2217	2260	2169	1810	1657	1588	1295	1709	1380
20. Actual Reserves (%) (19/2)x100	28.4	27.3	28.0	25.8	21.8	19.1	18.7	14.3	19.4	14.8

1/ Information not available.

Table 4C.18

PLANNED NET CAPABILITY AS OF JANUARY 1, BY TYPE OF FUEL - MW
Wisconsin - Upper Michigan Systems Group - WUMS

Summer Capability

Electric Region WUMS	Nuclear Steam	Coal Steam	- 0 1 -			- Natural Gas -			- Hydro -		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convent.	Pumped Storage	
1980	1515	5495	336	782	47	10	17	-	236	-	8438
% Total	17.9	65.1	4.0	9.3	0.6	0.1	0.2	-	2.8	-	100.0
1981	1515	6075	336	782	47	10	17	-	236	-	9018
% Total	16.8	67.4	3.7	8.7	0.5	0.1	0.2	-	2.6	-	100.0
1982	1515	6088	336	782	47	10	17	-	236	-	9031
% Total	16.8	67.4	3.7	8.7	0.5	0.1	0.2	-	2.6	-	100.0
1983	1515	6427	328	782	47	10	17	-	236	-	9362
% Total	16.5	68.0	3.6	8.5	0.5	0.1	0.2	-	2.6	-	100.0
1984	1515	6975	67	782	47	10	17	-	236	-	9650
% Total	15.7	72.3	0.7	8.1	0.5	0.1	0.2	-	2.4	-	100.0
1985	1515	7375	61	782	47	10	17	-	236	-	10043
% Total	15.1	73.4	0.6	7.8	0.5	0.1	0.2	-	2.3	-	100.0
1986	1515	7375	61	808	47	10	17	-	236	-	10067
% Total	15.1	73.2	0.6	8.0	0.5	0.1	0.2	-	2.3	-	100.0
1987	1515	7375	61	808	47	10	17	-	236	-	10069
% Total	15.1	73.2	0.6	8.0	0.5	0.1	0.2	-	2.3	-	100.0
1988	1515	7375	61	808	39	10	17	-	236	-	10061
% Total	15.1	73.2	0.6	8.0	0.5	0.1	0.2	-	2.3	-	100.0
1989	1515	7375	61	808	37	10	17	-	236	-	10059
% Total	15.1	73.3	0.6	8.0	0.4	0.1	0.2	-	2.3	-	100.0

Table 4C.19

MAJOR FUTURE GENERATING CAPABILITY, INSTALLATIONS, AND (REMOVALS)
WUMS Region

<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type (MW)</u>	<u>Net Summer Capability</u>	<u>Effective Date</u>	
					<u>(4/1/80) (ERA-411)</u>	<u>(4/1/79) (ERA-383)</u>
WI. EL. PWR.	Pleas. Prairie #1	ST	SUB	580	7/80	7/80
WI. PUB. SER.	Weston #3	ST	SUB	320	3/82	3/82
WI. EL. PWR.	Lakeside	ST	F02	(261)	4/83	1/82
WI. EL. PWR.	Pleas. Prairie #2	ST	SUB	580	4/83	4/82
WI. EL. PWR.	EDGEWATER #5	(ST	SUB	200)	3/84	6/83
WI. PUB. SER.		(ST	SUB	200)		
WI. PUB. SER.	Undetermined	ST	SUB	400	6/89	-
WI. PWR. & LT.	Haven	(NP	UR	172)	6/89 *	6/87
WI. PUB. SER.	Haven	(NP	UR	165)		
WI. EL. PWR.	Haven	(NP	UR	563)		

* Source: Nuclear News, February 1980; but not included in totals.

SECTION XI.5

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT
(MARCA)

XI.5.1

MID-CONTINENT AREA POWER POOL (MAPP) ELECTRIC REGION 20

Historical Perspective

The Mid-Continent Area Reliability Coordination Agreement (MARCA) was organized in 1968 and is one of the nine regional reliability councils comprising the National Electric Reliability Council (NERC). The MAPCA region covers all of the states of Iowa, Minnesota, Nebraska, North Dakota, most of South Dakota, and portions of the states of Illinois, Montana, and Wisconsin.

The MARCA organization provides an overview of the planning and operating activities in the region with respect to reliability. It presently has a membership of 28 systems consisting of 12 investor-owned utilities, 9 G & T cooperatives, 3 public power districts, 3 municipal utilities, and 1 federal agency. Otter Tail Power Company, Northwest Iowa Power Cooperative, Heartland Consumers Power District, Muscatine Power and Water, and Lincoln Electric System became MARCA members during 1979. Missouri Basin Municipal Power Agency became a MARCA member during 1980. Data for these six utilities is included in MARCA summaries. Manitoba Hydro-Electric Board is an associate member of MARCA; however, data for this Canadian utility is not included in this report.

A list of the systems for which data is included is shown below.

SYSTEMS INCLUDED IN MARCA MAPP REGION

Basin Electric Power Cooperative
Cooperative Power Association
Dairyland Power Cooperative
Eastern Iowa Light and Power Cooperative
Heartland Consumers Power District
Interstate Power Company
Iowa Electric Light and Power Company/
Central Iowa Power Cooperative
Iowa-Illinois Gas and Electric Company
Iowa Public Service Company/
Corn Belt Power Cooperative
Iowa Southern Utilities Company
Lake Superior District Power Company
Lincoln Electric System
Minnesota Power and Light Company
Minnkota Power Cooperative, Inc.
Missouri Basin Municipal Power Agency
Montana-Dakota Utilities Co.
Muscatine Power and Water
Nebraska Public Power District
Northern States Power Company

XI.5.2

Northwest Iowa Power Cooperative
Northwestern Public Service Company
Omaha Public Power District
Otter Tail Power Company
United Power Association
Western Area Power Administration -
Billings Area

MARCA regional operating practices and policies are established by the Mid-Continent Area Power Pool (MAPP) Operating Committee and are implemented by each system control center working in close cooperation with MAPP Coordination Center operating personnel. The MAPP control center is located in Minneapolis, Minnesota.

The MAPP organization is the regional power pool covering the same geographical area as MARCA and includes the same members. The difference in the two organizations is in their objective. MAPP's purpose is to promote the development of economy of service, as well as reliable and environmentally acceptable facilities. Rate schedules for various classes of service have been established for MAPP members and are on file with the Federal Energy Regulatory Commission (FERC).

Another major coordinating group in the region is the MSPSG (Missouri Basin Systems Group). The MSPSG conducts long-range power studies for its members with the objective of assuring that generation and transmission facilities are planned in the most efficient and economical manner. The MSPSG coordinates closely with DOE's Western Area Power Administration (WAPA). A Joint Transmission System (JTS) has been established which is a jointly planned, jointly-owned system administered by MSPSG and operated by WAPA.

Utilities in the MAPP region serve a population of 15 million with over 4 million electric customers. The MAPP region is the second largest in terms of geographical area of the NERC councils.

The transmission system is extensive with over 2000 miles of HVDC transmission at + 400kV, 3500 miles of 345 kV and 9000 miles of 230 kV. The region is interconnected with all neighboring regional councils, MAIN, SPP, and WSCC.

Coordination of MARCA with the Mid-America Interpool Network (MAIN) is effected through an Inter-Region Reliability Coordination Agreement which establishes an Inter-Region Review Committee with responsibilities relating to bulk power supply reliability of both planning and operating. Additionally, a statement concerning inter-regional cooperation with the Southwest Power Pool (SPP) has been exchanged, and a letter of agreement has been signed with the Western Systems Coordinating Council (WSCC) which provides for inter-regional planning and operating liaison, planning coordination committees as required, and an understanding that the coordination of operations relating to the East-West ties will be performed by the East-West Work Group of the WSCC Operations Committee.

XI.5.3

The MAPP region historically has been a summer peaking region, with the monthly coincident summer peak exceeding the winter peak by 4-14% in the past three years. The 1977-1979 summer and winter peaks are given below.

TABLE 5A.1
HISTORICAL PEAK DEMAND - MW
MAPP REGION

	<u>Summer</u>				<u>Winter</u>		
	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sept.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
1977	15801	<u>17549</u>	14078	13038	15097	<u>15454</u>	14787
1978	16141	<u>16981</u>	17580	<u>17596</u>	15616	<u>16198</u>	<u>16243</u>
1979	15632	17136	<u>18011</u>	<u>16473</u>	16153	<u>17332</u>	<u>16604</u>

Underline indicates seasonal peak

Shown below is a comparison of the region's non-coincident and coincident summer and winter peak demands for 1977-79.

TABLE 5A.2
COINCIDENT AND NON-COINCIDENT PEAK DEMANDS
MAPP REGION

	<u>Summer</u>			<u>Winter</u>		
	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
Coincident Pk. (MW)	17549	17596	18011	15454	16243	17332
Non-coincident Pk. (MW)	17607	18012	18162	15697	16570	17341
Diversity Factor	1.00	1.02	1.01	1.02	1.02	1.00

As seen in the above table, little regional diversity exists between the systems in the summer or winter period. However, there is seasonal diversity between the northern systems which peak in winter and the southern systems which peak in summer.

TABLE 5A.3
WINTER AND SUMMER PEAKING SYSTEM DIVERSITY
MAPP REGION

	<u>1978</u>			<u>1979</u>		
	<u>Summer Peak (MW)</u>	<u>Winter Peak (MW)</u>	<u>Difference (MW)</u>	<u>Summer Peak (MW)</u>	<u>Winter Peak (MW)</u>	<u>Difference (MW)</u>
Winter Peaking Systems	3214	5362	2148	3351	4304	953
Summer Peaking Systems	14798	11208	3590	14811	13037	1774

XI.5.4

In 1978 there was a potential 2148 MW which could have been exported to the south during the summer period and 3590 MW available for import to the northern systems during the winter period; in 1979, there were 953 MW and 1774 MW, respectively. Although the seasonal differences available for transfer varies each year, some can be utilized to delay installation of additional capacity in the region. Various contracts are in effect among the systems to utilize this geographic seasonal diversity. In addition, starting in 1980 there are also seasonal diversity exchanges of 500 MW into MARCA from Canada during the summer season and exports of 300 MW during the winter season.

The following table shows the scheduled maintenance performed each period and also the capability unavailable as a result of forced outages, or otherwise inoperable.

TABLE 5A.4
SCHEDULED MAINTENANCE AND UNAVAILABLE CAPACILITIES
MAPP REGION

	Summer			Winter		
	Scheduled Maintenance (MW)	Other Unavailable (MW)	Total Unavailable (MW)	Scheduled Maintenance (MW)	Other Unavailable (MW)	Total Unavailable (MW)
1977	436	1342	1778	932	2427	3359
1978	685	1696	2381	621	1888	2509
1979	615	1442	2057	2577	1491	4068

The capability unavailable for reasons other than scheduled maintenance varied from 6-8% of the planned capability in summer and from 6-13% in winter.

The reserve margins for the 1977-1979 seasonal periods are shown, considering the effects of scheduled maintenance and other outages.

TABLE 5A.5
HISTORICAL SEASONAL RESERVES
MAPP REGION

	Summer						
	Total Demand (MW)	Total Capability (MW)	Total Reserves (%)	Capabillity After Maintenance (MW)	Available Reserves (%)	Actual Capability (MW)	Actual Reserves (%)
1977	17607	22514	27.9	22078	25.4	20736	17.8
1978	18012	23833	32.3	23148	28.5	21452	19.1
1979	18162	25536	40.6	24921	37.2	23479	29.3
	Winter						
	Total Demand (MW)	Total Capability (MW)	Total Reserves (%)	Capabillity After Maintenance (MW)	Available Reserves (%)	Actual Capability (MW)	Actual Reserves (%)
1977	15697	22731	44.8	21799	38.9	19372	23.4
1978	16570	23922	44.4	23301	40.6	21413	29.2
1979	17341	26731	54.1	24154	39.3	22663	30.7

XI.5.5

The reserve margins shown on Table 5A.5 indicate that for the 1977-79 period sufficient capability was available to meet the demand requirements in both the summer and winter periods, after taking into account both scheduled and forced outages.

The energy requirements, summer and winter demands and annual load factors for the 1977-79 period are shown below.

TABLE 5A.6
HISTORICAL ENERGY, PEAKS AND LOAD FACTORS
MAPP REGION

Energy Requirement			Summer Demand		Winter Demand		Annual Load Factor
(GWH)	(Growth %)		(MW)	(Growth %)	(MW)	(Growth %)	(%)
1977	85738	-	17607	-	15697	-	55.6
1978	92477	7.9	18012	2.3	16570	5.6	58.6
1979	96518	4.4	18162	0.8	17341	4.7	60.7
% Growth,							
1977-79		6.1		1.6		5.1	--

The energy requirements grew at a compound growth rate of 6.1%. This can be compared to the 5.3% growth rate of WUMS in MAIN which is adjacent to MAPP on the east, and to the overall growth rate of MAIN of 3.0%. Apparently, the effects of conservation and economic slow down are not as pronounced in this region as in MAIN.

The summer demand shows little growth over the period, which is consistent with the growth of weather sensitive demands of the MAIN electric region. However, the winter demand growth rate is considerably higher than that of the adjacent MAIN Region (0.3%).

This is probably due to the fact that the northern systems of MAPP usually experience considerably colder winters than systems of other adjacent regions.

Current Perspective

The projected 1980 summer and winter demands are shown below.

TABLE 5A.7
PROJECTED 1980 SEASONAL PEAK DEMAND* - MW
MAPP REGION

Summer			Winter		
June	July	Aug.	Dec.	Jan.	Feb.
17542	19834	19413	17759	18674	17828

*Coincident as to month.

XI.5.6

The 1980 summer and winter demands are projected to occur in July and January, respectively. However, the peaks may occur in any month of the season depending on economic and climatic conditions. During the 1977-1979 period, the summer peak occurred in three different months.

The 1980 noncoincident summer peak-19949 MW is projected to be 0.6% greater than the summer coincident peak; and the noncoincident winter peak 18687 MW, 0.1% greater than the winter coincident peak reflecting a summer peak growth of 9.8% over 1979 and a winter peak growth of 7.8% over 1979-80. This growth is considerably higher than historical trends. The high rates of growth between 1979 and 1980 is probably due to the over estimation of the 1979 peaks, and the use of long term growth rate trends to estimate short term growth.

With little diversity, no opportunity exists for capacity savings due to monthly peak diversity in either season. However, as explained in the section on the Historic Perspective there is geographic diversity between northern and southern systems of which advantage is taken through contracts between the individual systems.

Another method of reducing capacity requirements is through load management techniques. An example of this is the extensive load management practice employed by a North Dakota power cooperative which resulted in an increase in the system's annual load factor of 55% in 1978 from 49% in 1977. The cooperative also advocates the use of electric heat, which is generated from non-scarce fuels, to replace oil-fired home and industrial heating use.

The 1980 winter demand is projected to be 6.3% less than the summer demand. Because of the nearly equal seasonal demands, scheduled maintenance is projected for both winter and summer periods. There are 932 MW scheduled for maintenance during the 1980 summer period and 1230 MW during the winter. These are 4.8% and 4.5% of the planned capability, respectively.

The 1980 summer planned capability of the MARCA region is estimated to be 25645 MW and the non-coincident peak demand is projected to be 19949 MW. The resultant reserve margins are shown below, taking into account receipts, deliveries and scheduled unavailable capacity.

TABLE 5A.8
1980 RESERVE MARGINS*
MAPP REGION

Summer						Winter					
Planned Reserves		Total Reserves		Available Reserves		Planned Reserves		Total Reserves		Available Reserves	
(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
5696	28.6	6366	31.9	5434	27.2	8635	46.2	8451	45.2	7221	38.6

*Based on ERA Form 411

The planned reserve requirements for systems in the MARCA region which are members of MAPP are determined by terms of the MAPP agreement. Currently, capacity obligation for each system is 15% greater than its annual system demand for a thermal system and 10% for a hydro system. The actual reserve margins for the 1980 summer and winter seasons are considerably greater than their requirements.

In addition to planned reserve margins, the systems in MARCA are required to maintain minimum operating reserves. The operating reserve is required to be sufficient to cover loss of capacity equal to 10% of the capability of the largest unit in service in MARCA. The spinning reserve portion of the operating reserve is required to be at least 75% of the capability of the largest unit in MARCA.

The peak load data includes 184 MW of interruptible demands during the summer peak and 337 MW during the winter peak. The summer and winter reserve margins would increase to 28.6% and 39.4%, respectively, if the peaks were adjusted to account for these loads.

The margins shown above have not been adjusted for unscheduled outages of capacity, as the amount of these outages are unknown ahead of time. If these outages do not exceed the maximum outages of the 1977-79 period, 8% of planned capacity during the summer period and 11% during the winter, the actual reserves would be 3382 MW or 17.0% and 4216 MW or 2.6% respectively, both in excess of reserve requirements.

The summer capability of the generating capacity planned in MAPP as of January 1, 1980 was 24950 MW. The capacity is shown below by type of fuel.

TABLE 5A.9
PLANNED SUMMER CAPABILITY, JANUARY 1, 1980-MW
MAPP REGION

	Nuclear Steam	Coal Steam	OIL			NATURAL GAS			P. HYDRO Conv.	P.S.	Total Capability
			ST	CT	IC	ST	CT	IC			
	3666	14232	543	2904	290	208	46	27	3034	--	24950
% of Total	14.7	57.0	2.2	11.6	1.2	0.8	0.2	0.1	12.2		100

The region depends heavily on non-scarce fuels, mostly coal, as the primary supply for its generating plants. Hydroelectric power however, comprising 12% of the regional capability is a very important factor. About 2500 MW of hydro capacity is installed in eight Federal projects located in the Missouri River Basin in the states of Montana, North Dakota, and South Dakota. The power output of these projects is marketed by DOE's Western Area Power Administration (WAPA).

XI.5.8

Baseload oil capability is insignificant, comprising only 543 MW or 2% of the current regional capability. However, there is a considerable amount of oil-fired combustion turbine capability (2900 MW). Oil conservation generation is employed in MAPP, primarily through import of Canadian hydro energy from Manitoba Hydro. The DOE Electric Power Monitoring Center in Washington, D.C. reported an estimated average daily savings of 10,700 barrels of oil in MAPP from April 1979 through February 1980 by importing hydroelectric energy.

The projected 1980 energy requirements, summer and winter demands, and annual load factor of the region are shown on table 5A.10.

TABLE 5A.10
1980 LOAD REQUIREMENTS
MAPP REGION

	<u>Energy Requirement</u> (GWH)	<u>Summer Demand*</u> (MW)	<u>Winter Demand*</u> (MW)	<u>Annual L.F.</u> (%)
	102285	19949	18687	58.4
% Growth 1980/79	6.0	9.8	7.8	

*Non-Coincident

The 1980 projected summer and winter demands are projected to grow at considerably higher rates than they did during the 1977-79 period - 1.6% and 5.1%, respectively, as previously discussed.

The projected 1980 energy requirements growth rate of 6.0% over 1979 requirements is in line with the historic 1977-79 rate of 6.1%.

Delays of future critical bulk power transmission facilities that will not be in service when needed are required to be reported under Item 5-C of the ERA-411 report. In the April 1, 1980 MARCA report 5 transmission lines were in this category. They are listed below in Table 5A.11.

TABLE 5A.11
LIST OF FUTURE CRITICAL BULK
POWER TRANSMISSION FACILITIES THAT
WILL NOT BE IN SERVICE WHEN REQUIRED
MAPP

	<u>System</u>	<u>Critical Facility</u>	<u>In-Service Date</u>		<u>Voltage (kV)</u> <u>Operating/Design</u>
			<u>Required</u>	<u>Expected</u>	
1.	DPC	Genoa-Lansing	1978	7/81	161/161

Reason for Delay

Original line route application denied by U.S. Fish and Wildlife Service.

XI.5.9

Revised line route permit approved by U.S. Fish and Wildlife Service. U.S. Corps of Engineers will not issue a permit for the river crossing in time to allow construction of the crossing during January/February, 1980. River crossing construction must be delayed until January/February, 1981.

Right-of-way to be acquired in Minnesota and Iowa for new line route.

<u>System</u>	<u>Critical Facility</u>	<u>In-Service Date</u>		<u>Voltage (kV)</u>	
		<u>Required</u>	<u>Expected</u>	<u>Operating/Design</u>	
II. DPC	Alma-Crystal Cave	12/79	7/81	161/161	

Reason for Delay

Because a permit was not granted for the original line route, a six to eight month delay in application resulted. This was due to the State of Wisconsin passing legislation, in the interim, which required an Agricultural Impact Statement (A.I.S.) to accompany a refiled application.

The Wisconsin Department of Natural Resources (DNR) objected to the original line route because the right-of-way near the Chippewa River crossing infringed on the Tiffany Wildlife Refuge.

Recently a permit for a river crossing which is acceptable to the Wisconsin DNR, the U.S. Corps of Engineers, and the U.S. Fish and Wildlife Service was received from the Corps of Engineers.

Subsequent to that the A.I.S. had to be resubmitted prior to purchase of right-of-way.

III. ISU	Ottumwa-Montezuma	1/1/80	12/80	345/345	
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Reason for Delay

Regulatory hearings.

IV. NPPD	Hoskins-Raun	1979	11/81	345/345	
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Reason for Delay

Delay due to litigation. Line must cross an Indian reservation.

V. NSP	Crystal Cave-Apple River	Now	11/80	161/161	
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Reason for Delay

Problems securing right-of-way.

Future Perspective

The range of net reserves for the MAPP region for the periods 1981-85 and 1986-89 are tabulated below:

TABLE 5A.12
RANGE OF TOTAL RESERVES - %
MAPP REGION

<u>1981-1985</u>		<u>1986-1989</u>	
<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
22-33	33-47	14.5-20	23-31

As shown, the low of 14.5% occurs in the summer of 1989 and the high of 47% in the winter of 1981/82. The MARCA Criteria for minimum reserves is 15% of the annual system demand and will be met for each peak season of the study period except in the summer of 1989. Using the MARCA criteria a deficit of 154 MW will result. The annual system demands in this report however do not reflect interruptible loads. If the 1989 summer interruptible demand of 251 MW are included, the reserves would be 727 MW, 97 MW above the minimum requirements or 15.3% as shown in the MARCA ERA 411 report.

Table 5A.13 shows the projected summer and winter peak demands and energy requirements for each of the study periods and the overall rate for the 1981-89 period.

TABLE 5A.13
LOAD REQUIREMENTS
MAPP REGION

	<u>Energy Requirements</u>		<u>Summer Peak Demand</u>		<u>Winter Peak Demand</u>		<u>Annual Load Factor</u>
	<u>GHW</u>	<u>Growth %</u>	<u>GHW</u>	<u>Growth%</u>	<u>GHW</u>	<u>Growth%</u>	
1981	107963	5.6	21275	6.6	19636	5.1	57.9
1982	112274	4.0	22529	5.7	20634	5.1	56.9
1983	118079	5.2	23678	5.1	21797	5.6	56.9
1984	124320	5.3	24911	5.2	22887	5.0	56.8
1985	130016	4.6	26096	4.8	24001	4.9	56.9
Growth 81-85		4.8		5.2		5.1	
1986	135913	4.5	27257	4.4	25094	4.6	56.9
1987	142090	4.5	28417	4.3	26226	4.5	57.1
1988	148265	4.3	29636	4.3	27423	4.6	57.0
1989	154652	4.3	30865	4.1	28736	4.8	57.2
Growth 86-89		4.4		4.2		4.6	
Growth 81-89		4.6		4.8		4.9	

The 1981-1985 summer demands are projected to grow at a compound rate of 5.2%; 1986-1989, 4.2%; and overall, 1981-1989, at 4.8%. These rates are considerably higher than the historic 1977-79 rate of 1.6%. However, since the historic 1977-79 winter demand and also the energy requirements are growing at much higher rates, the low growth of the summer peak may be atypical due to cooler than usual summers and therefore not represent a long-term slackening of demand. If lower summer demands than have been projected do occur, this will enhance the reserve situation.

The winter demand growth during the 1981-85 period is projected to be 5.1% and then to decrease to 4.6% in the 1986-89 period, with an overall rate of 4.9%. These are in the same range as the historic growth rate of 5.1%.

The energy requirements are projected to grow 4.8% during the 1981-85 period and 4.4% during 1986-89, with an overall growth rate of 4.6% for the 1981-89 period. This compares with a 6.1% historic rate for the 1977-79 period and a 6.0% rate projected for 1980. The growth rate of this region is somewhat greater than the 4.0% rate of the adjacent MAIN region.

The summer capability of units planned in the region during the 1980-1989 period is shown by type of fuel in Table 5A.19. Major generating unit additions during the period are given in Table 5A.20. The planned generating capacity by fuel type and prime mover for the target years 1980, 1984, and 1989 are given below.

TABLE 5A.14
PLANNED GENERATING CAPABILITY BY TYPE OF FUEL - %
MAPP REGION

SUMMER CAPABILITY

	<u>Nuclear</u>	<u>Coal</u>	<u>Oil</u>			<u>Natural Gas</u>			<u>Hydro</u>		<u>Total</u>
	<u>Steam</u>	<u>Steam</u>	<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>ST</u>	<u>CT</u>	<u>IC</u>	<u>Conv.</u>	<u>P.S.</u>	<u>Capability</u>
1980	14.7	57.0	2.2	11.6	1.2	0.8	0.2	0.1	12.2	-	100.0
1984	12.4	64.0	1.8	9.7	0.9	0.7	0.2	0.1	10.2	-	100.0
1989	10.7	69.3	1.2	8.4	0.8	0.6	0.1	0.1	8.8	-	100.0

Currently, coal is the primary fuel for 57% of the planned capacity of the region. This percentage is projected to increase to 64% by 1984 and to 69% by 1989, due to the addition of more than 20 new coal units. Nuclear units comprise about 15% of the total capability currently and is projected to decrease to 11% by 1989. No new nuclear units are planned for the 1981-89 period. There is only 543 MW of oil-fired steam capacity and 2904 MW of combustion turbine oil-fired capacity in the region. Natural gas steam capacity is 208 MW. No new oil or gas-fired capacity is scheduled for installation.

The adequacy and reliability of the region's transmission network is examined periodically for contingency response under various conditions by MARCA. An appraisal of the projected bulk power transmission network 4 to 6 years in the future is given under Item 6-B of the 1980 MARCA 411 report. It is stated in the appraisal that the MARCA bulk power transmission system will continue to be adequate so long as future facilities are placed in operation on a timely schedule, with no delays in licensing, or obtaining right-of-way, or other problems.

Results from the 1984 Summer MAIN Interchange Capability Study Including MAIN-MARCA and MAIN-ECAP-TVA Inter-Regional Reviews indicate that MARCA can export to MAIN 880 MW and import from MAIN 550 MW. These values based upon the study results have not been fine tuned for possible future operating conditions. It is expected that these values represent minimum expected values, with the export and import values actually realized being higher.

Results from informal joint MARCA/SPP transfer capability studies for 1984 Summer indicate that MARCA can export to SPP 475 MW and import from SPP 1300 MW. With an optimized generation pattern and transmission line configuration, both the export and import capabilities would be higher.

Table 5A.15

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
MAPP Region

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	21079	22092	22096	22850	24904	26040
2. Peak Demand	17607	15697	18012	16570	18162	17341
3. Planned Reserves (1-2)	3472	6395	4084	6280	6742	8699
4. Planned Reserves (%) $(3/2) \times 100$	19.7	40.7	22.7	37.9	37.1	50.2
5. Net Transactions (Imports-Exports)	1435	639	1737	1072	632	691
6. Total Capability (1+5)	22514	22731	23833	23922	25536	26731
7. Total Reserves (6-2)	4907	7034	5821	7352	7374	9390
8. Total Reserves (%) $(7/2) \times 100$	27.9	44.8	32.3	44.4	40.6	54.1
9. Scheduled Maintenance	436	932	685	621	615	2577
10. Capability after Maintenance (6-9)	22078	21799	23148	23301	24921	24154
11. Reserves after Maintenance (10-2)	4471	6102	5136	6731	6759	6813
12. Reserves after Maintenance (%) $(11/2) \times 100$	25.4	38.9	28.5	40.6	37.2	39.3
13. Inoperable Capability	0	0	0	0	0	0
14. Available Capability (10-13)	22078	21799	23148	23301	24921	24154
15. Available Reserves (14-2)	4471	5102	5136	6731	6759	6813
16. Available Reserves (%) $(15/2) \times 100$	25.4	38.9	28.5	40.6	37.2	39.3
17. Forced Outages	1342	2427	1696	888	1442	1491
18. Actual Capability after Forced Outages (14-17)	20736	19372	21452	21413	23479	22663
19. Actual Reserves (18-2)	3129	3675	3440	4843	5317	5322
20. Actual Reserves (%) $(19/2) \times 100$	17.8	23.4	19.1	29.2	29.3	30.7

1/ Included in Item 17.

Table 5A.16

Current Capability (MW) and Reserves (MW and Percent)
MAPP Region

	1980	
	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	25645	27322
2. Peak Demand	19949	18687
3. Planned Reserves (1-2)	5696	8635
4. Planned Reserves (%) $(3 \div 2) \times 100\%$	28.6	46.2
5. Net Transactions (Imports-Exports)	670	-184
6. Total Capability (1+5)	26315	27138
7. Total Reserves (6-2)	6366	8451
8. Total Reserves (%) $(7 \div 2) \times 100\%$	31.9	45.2
9. Scheduled Maintenance	932	1230
10. Capability After Maintenance (6-9)	25383	25908
11. Reserves After Maintenance (10-2)	5434	7221
12. Reserves After Maintenance (%) $(11 \div 2) \times 100\%$	27.2	38.6
13. Inoperable Capability*	0	0
14. Available Capability (10-13)	25383	25908
15. Available Reserves (14-2)	5434	7221
16. Available Reserves (%) $(15 \div 2) \times 100\%$	27.2	38.6
17. Forced Outages*	0	0
18. Actual Capability After Forced Outages (14-17)	25383	25908
19. Actual Reserves (18-2)	5434	7221
20. Actual Reserves (%) $(19 \div 2) \times 100\%$	27.2	38.6

*No data provided.

Table 5A.17

Future Capability (MW) and Reserves (MW and Percent)
MAPP Region

	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	27619	29093	28707	29500	29449	30712	29842	31343	31274	32199
2. Peak Demand	21275	19636	22529	20634	23678	21797	24911	22887	26096	24001
3. Planned Reserves (1-2)	6344	9457	6178	8866	5771	8915	4931	8456	5178	8198
4. Planned Reserves (%) (3÷2) x 100%	29.8	48.2	27.4	43.0	24.4	40.9	19.8	36.9	19.8	34.2
5. Net Transactions (Imports-Exports)	565	-219	525	-291	660	-228	651	-235	643	-240
6. Total Capability (1+5)	28184	28874	29232	29209	30109	30484	30493	31108	31917	31959
7. Total Reserves (6-2)	6909	9238	6703	8575	6431	8687	5582	8221	5821	7958
8. Total Reserves (%) (7÷2) x 100%	32.5	47.0	29.8	41.6	27.2	39.9	22.4	35.9	22.3	33.2
9. Scheduled Maintenance-No data prov. after '81	837	1570	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	27347	27304	29323	29209	30109	30484	30493	31108	31917	31959
11. Reserves After Maintenance (10-2)	6072	7668	6703	8575	6431	8687	5582	8221	5821	7958
12. Reserves After Maintenance (%) (11÷2) x 100%	28.5	39.1	29.8	41.6	27.2	39.9	22.4	35.9	22.3	33.2
13. Inoperable Capability-No data provided	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	27347	27304	29323	29209	30109	30484	30493	31108	31917	31959
15. Available Reserves (14-2)	6072	7668	6703	8575	6431	8687	5582	8221	5821	7958
16. Available Reserves (%) (15÷2) x 100%	28.5	39.1	29.8	41.6	27.2	39.9	22.4	35.9	22.3	33.2
17. Forced Outages-No data provided	0	0	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	27347	27304	29323	29209	30109	30484	30493	31108	31917	31959
19. Actual Reserves (18-2)	6072	7668	6703	8575	6431	8687	5582	8221	5821	7958
20. Actual Reserves (%) (19÷2) x 100%	28.5	39.1	29.8	41.6	27.2	39.9	22.4	35.9	22.3	33.2

Table 5A.18

Future Capability (MW) and Reserves (MW and Percent)
MAPP Region

	1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	31593	32362	33497	34753	33901	35382	34726	35582
2. Peak Demand	27257	25094	28417	26226	29636	27423	30865	28736
3. Planned Reserves (1-2)	4336	7268	5080	8527	4265	7959	3861	6846
4. Planned Reserves (%) (3-2) x 100%	15.9	29.0	17.9	32.5	14.4	29.0	12.5	23.8
5. Net Transactions (Imports-Exports)	738	-246	730	-353	626	-356	615	-264
6. Total Capability (1+5)	32331	32116	34227	34400	34527	35026	35341	35318
7. Total Reserves (6-2)	5074	7022	5810	8174	4891	7603	4476	6582
8. Total Reserves (%) (7-2) x 100%	18.6	28.0	20.4	31.2	16.5	27.7	14.5	22.9
9. Scheduled Maintenance*	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	32331	32116	34227	34400	34527	35026	35341	35318
11. Reserves After Maintenance (10-2)	5074	7022	5810	8174	4891	7603	4476	6582
12. Reserves After Maintenance (%) (11-2) x 100%	18.6	28.0	20.4	31.2	16.5	27.7	14.5	22.9
13. Inoperable Capability*	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	32331	32116	34227	34400	34527	35026	35341	35318
15. Available Reserves (14-2)	5074	7022	5810	8174	4891	7603	4476	6582
16. Available Reserves (%) (15-2) x 100%	18.6	28.0	20.4	31.2	16.5	27.7	14.5	22.9
17. Forced Outages*	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outages (14-17)	32331	32116	34227	34400	34527	35026	35341	35318
19. Actual Reserves (18-2)	5074	7022	5810	8174	4891	7603	4476	6582
20. Actual Reserves (%) (19-2) x 100%	18.6	28.0	20.4	31.2	16.5	27.7	14.5	22.9

*No data provided.

Table 5A.19

PLANNED SUMMER CAPABILITY AS OF JANUARY 1, BY TYPE OF FUEL
MAPP Region

Electric Region 20-MAPP	Nuclear Steam	Coal Steam	<u>Oil</u>			<u>Natural Gas</u>			<u>Hydro</u>		Total Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Comb. Turb.	I.C.	Convent.	Pumped Storage	
1980	3666	14232	543	2904	290	208	46	27	3034	--	24950
% Total	14.7	57.0	2.2	11.6	1.2	0.8	0.2	0.1	12.2	--	100
1981	3691	15930	543	2903	296	208	46	27	2984	--	26628
% Total	13.9	59.8	2.0	10.9	1.1	0.8	0.2	0.1	11.2	--	100
1982	3695	17405	543	2904	296	208	46	27	2946	--	28070
% Total	13.2	62.0	1.9	10.3	1.1	0.7	0.2	0.1	10.5	--	100
1983	3695	17910	523	2904	289	208	46	27	2977	--	28579
% Total	12.9	62.7	1.8	10.2	1.0	0.7	0.2	0.1	10.4	--	100
1984	3695	19112	523	2904	282	208	46	27	3059	--	29856
% Total	12.4	64.0	1.8	9.7	0.9	0.7	0.2	0.1	10.2	--	100
1985	3695	19762	523	2904	282	208	46	27	3057	--	30504
% Total	12.1	64.7	1.7	9.5	0.9	0.7	0.1	0.1	10.2	--	100
1986	3695	20687	523	2904	282	208	46	27	3057	--	31429
% Total	11.8	65.8	1.7	9.2	0.9	0.7	0.1	0.1	9.7	--	100
1987	3695	20967	498	2904	680	208	46	27	3015	--	31640
% Total	11.7	66.3	1.6	9.2	0.9	0.6	0.1	0.1	9.5	--	100
1988	3695	23457	435	2904	266	199	46	27	3015	--	34044
% Total	10.8	68.9	1.3	8.5	0.8	0.6	0.1	0.1	8.9	--	100
1989	3695	23957	435	2904	266	199	46	27	3045	--	34574
% Total	10.7	69.3	1.2	8.4	0.8	0.6	0.1	0.1	8.8	--	100

Table 5A.20

MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS AND (REMOVALS)
MAPP Region

<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type</u>	<u>Summer Capability</u>	<u>April '80 ERA-411 Effective Date</u>	<u>April '79 ERA-383 Effective Date</u>
MN. Pwr. & Lt.	Clay Boswell	St	Sub	500	5-01-80	5-80
Coop. Pwr. Assn.	Coal Creek	St	Lib	238.36	11-01-80	11-80
United Pwr. Assn.	Coal Creek			222.64		
Ia. El. Lt. & Pwr.	Ottumwa			100	12-31-80	12-80
Ia. Lt. Gas & El.	Ottumwa	St	Sub	125		
Ia. Pwr. & Lt.	Ottumwa			100		
Ia. Pub. Ser.	Ottumwa			125		
Ia. So. Utils.	Ottumwa			225		
				<u>1681</u>		
Basin El. Pwr. Coop.	Laramie	St	Sub	174	4-01-81	10-80
Heartland C.P.D.	Laramie			28		
Lincoln, NE	Laramie			133.3		
Mo. Basin Mun. Pup.	Laramie			164.7		
Mont. Dak. Utils.	Coyote	St	Lig	82	5-01-81	5-81
Minnkota Pub. Coop.	Coyote			123		
MN. Pwr. & Lt.	Coyote			20.5		
N.W. Pub. Serv.	Coyote			41		
Otter Tail Pwr.	Coyote			143.5		
Neb. P.O.D.	Gentlemen	St	Sub	600	11-01-81	5-81
				<u>1510</u>		
Basin El. Pwr. Coop.	Antelope Valley 1	St	Lig	416	4-15-82	4-82
Muscantine, Ia	Muscantine	St	Bit	150	5-01-82	5-82
				<u>566</u>		
Ia. Il. Gas & El.	Louisa	St	Sub	300	7-01-83	1-83
Ia. Pwr. & Lt.	Louisa			211		
Ia. Pub. Serv.	Louisa			100		
Eastern Ia. Lt & Pwr.	Louisa			30		
Basin El. Pwr. Coop.	Antelope Valley 2	St	Lig	416	11-01-83	11-83
				<u>1057</u>		
Ia. El. Lt. & Pwr.	Guthrie Cty.	St.	Col	400	12-31-84	12-84
Ia. Pwr. & Lt.	Guthrie Cty.			100		
Ia. So. Utils.	Guthrie Cty.			150		
				<u>650</u>		

Table 5A.20

MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS AND (REMOVALS) (Cont.)
MAPP Region

<u>System</u>	<u>Station</u>	<u>Unit Type</u>	<u>Fuel Type</u>	<u>Summer Capability</u>	<u>April '80 ERA-411 Effective Date</u>	<u>April '79 ERA-383 Effective Date</u>
Northern St. Pwr.	Sherburne Cty.	St	Sub	780	5-01-85	5-84
Lake Sup. Dist. Pub.	Sherburne Cty.			20		-
Otter Tail Pwr.	Spiritwood	St	Lig	125	11-01-85	-
				<u>925</u>		
Eastern Ia. Lt. & Pwr.	Allied	St	Bit	50	5-01-85	5-86
Heartland C.P.D.	Allied			30		-
Ia. Pub. Serv.	Allied			100		-
Mo. Basin Mun. Pwr.	Allied			50		-
N.W. Ia. Pwr. Coop.	Allied			50		-
				<u>280</u>		
Basin El. Pwr. Coop.	Antelope Valley 3	St	Lig	400	4-01-87	-
Mont. Dak. Utils.	Not Given	St	Lig	100	5-01-87	-
Neb. P.P.D.	Not Given	St	Lig	600	5-01-87	-
Ia. Pub. Serv.	Neal	St	Sub	200	5-01-87	-
Northern St. Pwr.	Not Given	St	Sub	620	5-01-87	-
Lake Sur Dist. Pwr.	Not Given			50		-
Dairyland Pwr. Coop.	Not Given	St	Sub	520	11-01-87	-
				<u>2490</u>		
Mn. Pwr. Lt.	Not Given	St	Lig	275	11-01-88	-
Northern St. Pwr.	Not Given			175		-
Ottertail Pwr.	Not Given			50		-
				<u>500</u>		
Northern St. Pwr.	Not Given	St	Sub	200	5-01-89	-

SECTION XI.6
NORTHEAST POWER COORDINATING COUNCIL
(NPCC)

NORTHEAST POWER COORDINATION COUNCIL

Introduction

The Northeast Power Coordinating Council (NPCC) includes twenty-one utility system members located in the six New England states, New York, Ontario and New Brunswick. There are four operating entities or subregions--two in the United States, and two in Canada. This report primarily addresses the United States portion of the Council, a relatively small area geographically. It has a high population density and accounts for about ten percent of the total generation in the contiguous United States.

The U.S. portions of the NPCC are heavily dependent on oil as a boiler fuel and approximately one half of all the electric energy produced in the region was supplied by imported oil-fired generation, requiring in excess of 160 million barrels of oil in 1979. As such, it is the largest oil consumer of all the regions in NERC.

The two U.S. subregions, or operating pools, are the New England Power Pool (NEPOOL) and the New York Power Pool (NYPP). The New England Power Pool operates in the states of Maine, Vermont, New Hampshire, Massachusetts, Rhode Island and Canada. This region was the seat of the industrial revolution in the United States. However, today these states are no longer as industrially-intensive as a result of the general exodus of the textile industry and reduced lumber production. Many small factories that were once located in these states have closed down due to a variety of economic constraints. Industry originally located in the New England states because the many rivers provided an economical source of hydro power. When industry departed, several of these sources fell into disuse. However, the present high cost of imported oil used to provide energy has resulted in a re-evaluation of the generating sites for new small hydro electric generation.

The New York Power Pool is unique in that it is the only integrated operating region within a single state. As a result of low cost hydro-electric energy in the northern tier of the State, particularly Niagara Falls, several large power intensive industries are located here. Included are aluminum refineries and chemical plants. The area has a large capacity transmission interconnection with Canada.

The New England Power Pool is a winter peaking system, while NYPP is a summer peaking group. However, there is a little inter-pool diversity. Each pool takes advantage of intra-system diversity in establishing reserve criteria.

For the 1981-1989 period, the aggregate electric non-coincidental peak load growth for New England and New York is forecasted at 2.5 percent compounded annually. About 5,786 MW of the planned major additions to meet this growth is nuclear. However, if no new capacity--either coal or nuclear--were to come on line after 1979, oil consumption would increase by about 100 million barrels per year.

Table 6.1

Planned Capacity Exchanges
Northeast Power Coordinating Council

<u>Imports</u>	<u>1981</u>		<u>1982</u>		<u>1983</u>		<u>1984</u>		<u>1989</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
Hydro Quebec	800.0	0	800.0	0	800.0	0	800.0	0	800.0	0
Metro District	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
N.E. Industrials	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
New Brunswick	431.0	431.0	431.0	430.0	430.0	430.0	430.0	430.0	29.0	29.0
So. Canada	19.9	0	21.5	0	23.1	0	24.8	0	28.6	0
Ontario Hydro	13.8	15.7	15.7	17.7	17.7	19.6	19.6	19.6	0	0

NOTE: There are no scheduled exports.

Table 6.2

EMERGENCY INTERREGIONAL TRANSFER CAPABILITIES *
Northeast Power Coordinating Council

	<u>1979-Summer</u> (MW)	<u>1988-Summer</u> (MW)
NPCC-MAAC	3,300	4,400
MAAC-NPCC	1,900	2,450
NPCC-ECAR	3,300	2,000
ECAR-NPCC	2,200	3,100

* Based on NERC 9th Annual Review.

The above figures are incremental over assumed base schedules.

Anticipated inter-area transfer capabilities for the summer of 1984 are shown in the following table:

Table 6.3

INTER-AREA TRANSFER CAPABILITIES NORMAL/EMERGENCY - MW
Northeast Power Coordinating Council

	<u>1984-Summer</u>
New York-New England	1,600 / 1,800
New England-New York	1,375 / 1,375
New York-Ontario Hydro	1,050 / 1,300
Ontario Hydro-New York	1,250 / 1,650
New England-New Brunswick	-280 * / -0-
New Brunswick-New England	600 / 600

* A long-term contract for 400 MW sale to New England exists in this time period. The indicated -280MW limitation in transfer capability to New Brunswick is actually 120 MW above base.

The transfer capabilities shown are non-simultaneous and are calculated on the basis of total power flow on all direct interconnections between the two participating areas and, therefore, are independent of base schedule transfers between areas, and also consider parallel paths rather than only the direct ties.

The DOE Division of Power Supply and Reliability/ERA is conducting preliminary investigations into strengthening the transmission system between Ohio and Canada via Pennsylvania and New York.

Table 6.4

INTERRUPTABLE LOAD CONTRACTS
Northeast Power Coordinating Council

<u>Utility Name</u>	<u>Number of Customers</u>	<u>Total Load (KW)</u>	<u>Interrupt Load (KW)</u>	<u>Maximum Time (Hrs/Yr)</u>	<u>Maximum Frequency (Time/Yr)</u>	<u>Lead Time (Mins)</u>	<u>Reaction Time (Mins)</u>	<u>Vehicle for Interruption</u>	<u>Cause of Interrupted Load</u>
<u>NYPP</u>									
Central Hudson Gas & Electric Co.	Ncne	-	-	-	-	-	-	-	-
Consolidated Edison Co. of N.Y., Inc.	Ncne	-	-	-	-	-	-	-	-
Long Island Lighting Co.	Ncne	-	-	-	-	-	-	-	-
Niagara Mohawk Power Corp.	3	5,284,000	1,430,000	-	-	-	-	Phone	Pre-planned Schedule
Orange & Rockland Utilities, Inc.	Ncne	-	-	-	-	-	-	-	-
Power Authority of the State of N.Y.	2	265,000	39,000	-	-	14400	1440	Letter/Phone	Lowflow of water and ice condition
New York State Electric Corp.	None	-	-	-	-	-	-	-	-
Rochester Gas & Electric Corp.	*	<u>1,000,000</u>	<u>25,000</u>	-	-	15	15	Phone	High Demand
TOTAL	5	6,549,000	1,494,000	-	-	-	-	-	-
<u>NEPEX</u>									
Bangor Hydro-electric Company	1	50,000	45,000	600	10	30	10	Phone/switch	High Energy Cost at peak
Boston Edison Co.	1	6,000	6,000	200	5	10	10	Phone/switch	NEPEX requested and due to the load condition
Cambridge Electric Light Co.	2	-	30,000	-	2	-	-	Phone	Voltage reduction
Central Main Power	**	128,000	33,500	-	10	4	4	Radio/TV	High Demand

ELECTRIC REGION 3 - NEW ENGLAND POWER POOL

Historical Perspective

NEPOOL, the operating pool for over forty variously sized privately and publicly-owned utilities, has its power coordinating center in Springfield, Massachusetts. From there, operations are coordinated with four satellite centers in Connecticut, Vermont, New Hampshire, and Maine, where electric plant generation is actually dispatched. While most of the geographical area is suburban and rural, there are several large cities, particularly along the coastal regions. As a result of its geography, the Region is almost totally dependent on expensive mid-east imported oil--a supply which, at best, is insecure--to meet fossil fuel requirements. Thus, all major capacity planning has been focused on nuclear power. While the Region is now favored with large reserves as a result of planning scenarios that did not materialize, the present attitudes toward nuclear plants could present major reliability problems should any of the now planned and under construction units be cancelled. At best, even if these nuclear generators are not needed to meet immediate power, their output would be useful toward reducing oil imports.

The climate of the area, particularly the northern states, is such that the area is a winter peaking system. However, the difference between the summer and winter peak is only five percent, thus providing little intra-regional, seasonal diversity. With the high cost of oil, a primary heating fuel, electric heating is developing a resurgence, thus creating an increase in the winter peak.

Growth in the area since 1977 has been very small, with an average annual winter peak growth of 1.5 percent and energy growth of 2.6 percent. This can be attributed to mild weather and the increasing costs of electric power. Actual figures as obtained from respondent reports are shown below:

Table 6A.1

HISTORICAL PEAK DEMAND AND ENERGY *
New England Power Pool

NEPOOL Load Growth *

<u>Year</u>	<u>Net Energy</u>		<u>Summer Peak</u>		<u>Winter Peak</u>		<u>Load Factor</u>
	<u>GWH</u>	<u>% Change</u>	<u>MW</u>	<u>% Change</u>	<u>MW</u>	<u>% Change</u>	
1977	79,734	-	14,194	-	14,822	-	61
1978	82,505	3.5	14,404	1.5	15,072	1.7	62
1979	83,958	1.8	14,324	-0.6	15,278	1.4	63

*Based on ERA-411 Form.

The table indicates that extrapolating average annual growth based on several years could lead to erroneous conclusions, as the growth in the later years is well below those of the earlier years.

The New England companies anticipated the present fuel supply situation many years ago, and thus committed the area to nuclear power. As early as 1978, the Region included nine percent of the total nuclear capacity of the United States and generated in the contiguous states. This translates into twenty percent of New England capacity and thirty-five percent of the Region's plant output for that year.

The following table indicates the plant output percentage by fuel type for NEPOOL:

Table 6A.2

PERCENT GENERATION BY FUEL TYPE *
New England Power Pool

<u>Year</u>	<u>Nuclear</u>	<u>Hydro</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
1977	33	7	3	57	0
1978	35	5	3	57	0
1979	34	6	4	55	1

Table 6A.3

PERCENT NET DEPENDABLE CAPABILITY BY FUEL TYPE
New England Power Pool

<u>Year</u>	<u>Nuclear</u>	<u>Hydro</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
[Winter] 1978-79	22.6	6.2	2.3	68.8	0.1

*Based on EIA Form 4 data and 1979 NERC Summary.

For the purposes of these comparisons, the pump storage figures have been deleted as they generally require fossil fuel input for hydro output.

The total nuclear generation for 1979 was below that of 1978 due to several administrative outages and a prolonged outage of the Maine Yankee Plant. The total plant output for the Region was also reduced as a result of increased purchases from coal-burning utilities in the West. This transfer of energy helped to reduce the amount of oil generation even though there was a reduction in nuclear plant output.

A breakdown of the actual 1978 generation by fuel type is listed below for comparative purposes. The winter capability is also indicated in the table:

Table 6A.4

1978 NET DEPENDABLE CAPABILITY AND GENERATION
BY PRIME MOVER AND FUEL TYPE *

New England Power Pool

<u>Prime Mover</u>	<u>Type</u>	<u>Fuel MW</u>	<u>% Total</u>	<u>G W H</u>	<u>% Total</u>
Steam	Nuclear	4,250	19.4	27,980	35.0
Steam	Coal	456	2.1	1,969	2.5
Steam	Oil	11,807	53.9	45,571	57.1
Steam	Gas	0	0	0	0
Hydro	-	1,232	5.6	4,409	5.5
Pump Storage	-	1,633	7.5	-444	-0.6
Gas Turbine	Oil	1,735	7.9	104	0.1
Gas Turbine	Gas	0	-	0	-
Combine Cycle	Oil	206	0.9	293	0.4
Combine Cycle	Gas	0	0	0	0
Other (Interchange)	-	600	2.7	0	0

* 1979 NERC Summary of Peak Load & Capability.

To produce this energy, fuel requirements were:

802,000 tons of coal.

595,000 barrels of distillate oil.

75 million barrels of residual oil.

2.6 million MCF natural gas.

Thus, 13.6 percent of the total residual oil used to produce electricity in the United States is consumed in New England. The Region is not predicting any future use of natural gas as a fuel, as only a temporary exemption for its use has been given by FERC.

There are six nuclear units in operation in the Region. Outage of these units to upgrade safety features as a result of the Three Mile Island lessons learned will not adversely affect system reliability. There were adequate reserves to meet the peak loads during 1977, 1978, and 1979.

The minimum planned reserves as a percent of the peak load varied between 38 percent and 40 percent for the winter and was up to 43 percent in the summer as a percent of the peak load. After considering net sales and purchases and unavailable capacity over the peak, these figures were reduced to as low as zero in the summer and 11 percent in the winter. The Table 6A.8 shows reserves for the 3-year period 1977-1979, and it can be seen that this compares favorably with the planned reserve criteria of 23 percent to 24 percent as established by the NEPOOL Agreement.

As a result of intra-pool diversity, the individual company reserves can be as low as 18 percent and still meet the overall pool criteria. The planned reserves are the results of forecast decisions in 1975, which was a time of 7.5 percent load growth. Since then, there has been a 5,000 MW reduction in forecasted load growth due to economic changes and the oil embargo.

In general, the reserve criterion is a function of the mix and maturity of the net dependable capacity. With the recent increase in system load factor, this figure has had to increase as there is less off-peak excess capacity available for planned maintenance. Also, since the inter-regional ties to the North are of low capacity, the area is assumed to be a peninsular system and thus requires higher reserves than a region with interconnections on several sides. Consequently, NEPOOL has transmission ties equal to about four percent of installed capacity as compared to NYPP where the interconnection ties equal about ten percent of installed capacity.

The NEPOOL Agreement states that operating reserves equal to one and one-half times the capacity of the largest unit on the line must be maintained. Of this, one-half must be available in thirty minutes. Capacity equal to the largest possible system contingency must be available in ten minutes--of this, one-third of that capacity must be synchronized.

Additional load relief of two percent is available with a five percent voltage reduction and, generally, public appeals result in another one and one-half percent of load reduction. NEPOOL companies have interruptable load contracts with seven customers providing an additional 130 MW of capacity during emergencies. This information is detailed in Table 6.4.

The transmission system includes 444 miles of 230 KV lines and 1,539 miles of 345 KV lines. The transmission is adequate for handling the area loads and energy transfers with reserve for economy and oil conservation transactions. All transmission system constraints are thermal rather than stability limited.

With rising fuel oil prices, home heating with electricity is becoming more attractive in the area even though the cost of electric power is increasing. In an area with a winter peak, this situation is less than ideal for the power companies and, as such, some form of load management is becoming important. Several companies in the area have timers on water heaters to reduce peak loads, and experimental systems with ripple control have been installed. Additionally, some companies have seasonal rates. The companies are also assisting their customers in the use of heat storage systems for home heating rather than base-board or similar types of heating systems. With the area's prevailing cool summer temperatures and lack of need for air-conditioning, heat pumps for home climate control are not economically viable.

Current Perspective

The anticipated winter 1980-81 peak for the NEPOOL System is 16,110 MW and is expected to occur in January 1981, which would then be an increase of 3.2 percent over the 1979-80 winter peak. This is a decrease in estimated growth as compared to the previous forecast for this period. The summer 1980 peak is forecast at 14,190 MW and is a one percent decrease from the 1979 forecast for the corresponding period. Total net energy for 1980 is anticipated at 86,219 GWH, representing a 2.6 percent growth over 1979--a somewhat larger increase than was experienced in the previous year. The annual load factor anticipated in 1980 is 62 percent. To meet this load, the planned capability and resultant margins to meet the 1980 summer and winter peaks are shown in Table 6A.9.

While the reserves after maintenance do not reflect the additional daily forced outages of about fifteen percent, the Region will have reserves well in excess of agreement criteria for the year 1980.

To meet the forecasted energy requirements of 86,219 GWH, fuel requirements are anticipated at one million tons of coal, one million barrels of distillate oil, and over 100 million barrels of residual oil. These figures are based on normal hydro plant operation. However, the Region experienced abnormally dry weather during the early part of 1980, resulting in very little snow cover. The lack of run-off from snow will reduce hydro output in the spring unless there is a change in the precipitation cycle. Without spring run-off, there could be an increase in residual oil consumption of 800,000 barrels to make up for the loss in hydro plant output.

There are no major transmission projects scheduled for completion during 1980. The transmission system is adequate to cover load commitments for the year with no stability problem areas. In general, thermal rating is the controlling factor limiting transfers. Transmission additions scheduled for 1980 include 52.4 miles of 115 and 138 KV and twelve miles of 345 KV.

Future Perspective

The 1981 through 1989 period forecasts include an average winter peak growth of 2.6 percent per year, an increase from the previous average of 1.5 percent per year--for 1978 and 1979. In the first five years of the period, the expected growth is at the 2.4 percent rate with the balance of the period at 2.8 percent per year. Tables 6A.10.1 and 6A.10.2 show projected reserve margins for the 1981-1989 period. Energy requirements during the same 9-year period are expected to increase at a rate of 2.6 percent.

While these reserves exceed the NEPOOL Agreement criteria, they are based on a very moderate load growth and timely completion of capacity--planned and under construction. As can be noted in the table listing the future plants (shown later in this report), original planned in-service dates are rarely met. Thus, either unit construction slippage or increased load growth could rapidly erode these margins.

To meet the projected load growth, approximately 5,521 MW of new base load generating capacity additions are planned. This will include 4,612 MW of nuclear, 568 MW of coal-fired, and 341 MW of oil capacity.

The following tabulation indicates the proportioning of capacity for the years 1984 and 1988 at the time of the winter peak:

Table 6A.5

WINTER PLANNED CAPABILITY (%) BY PRIME MOVER AND FUEL TYPE *
New England Power Pool

<u>Prime Mover</u>	<u>Fuel Type</u>	<u>1984 % of Total</u>	<u>1988 % of Total</u>
Steam	Nuclear	22.9	34
Steam	Coal	6.9	8
Steam	Oil	45.0	36
Steam	Gas	0	
Hydro			5
Pumped Storage		6.9	6
Gas Turbine	Oil	8.0	7
Gas Turbine	Gas	0	
Combined Cycle	Oil	2.3	2
Combined Cycle	Gas	0	
Other		2.6	2

* Based on the 1979 NERC Summary of Projected Peak Load & Capability, modified to reflect latest ERA-411 Form data.

The estimated plant output for 1984 is 109,785 GWH, and the forecasted fuel requirements to meet this generation are 2.9 million tons of coal, 106 million barrels of residual oil, and 2.6 million barrels of distillate oil. The corresponding requirements to meet the 1988 generation of 130,444 GWH are 5.7 million tons of coal, 82.7 million barrels of residual oil, and 2.4 million barrels of distillate oil. These figures also indicate the regional commitment to reducing dependence on imported oil.

Listed below are the major nuclear and coal units planned and under construction for the Region. Shown in the table is the historical slippage experienced for each of the planned units.

Table 6A.6

PLANNED MAJOR CAPACITY ADDITIONS
New England Power Pool

<u>Utility</u>	<u>Plant Name</u>	<u>Name Plate Capacity</u>	<u>Original In-Service Date</u>	<u>In-Service Date as of April 1979</u>	<u>Present In-Service Date</u>
<u>N u c l e a r</u>					
NOEU	Millstone #3	1150	May 1979	May 1986	May 1986
PSNH	Seabrook #1	1150	Nov 1979	Apr 1983	Apr 1983
PSNH	Seabrook #2	1150	Nov 1981	Feb 1985	Feb 1985
BOEC	Pilgrim #2	1150	Nov 1978	Dec 1985	Dec 1985
NEES	NEPCO #1	1150	Apr 1982	Nov 1987	Cancelled
NEES	NEPCO #1	1150	Nov 1983	Nov 1989	Cancelled
<u>C o a l</u>					
CEMP	Sears Island	568	Nov 1983	Nov 1987	Nov 1989

The above dates are based on data in the April 1980 ERA-411 Form. A recent survey made of the individual system companies reveals no additional slippage since that time.

A critical transmission addition for the period is the West Walpole-Needham 345 KV line, located in the Boston area. Completion of this line has been delayed two years due to regulatory hearings and approvals. The delay will impact the reliability of the transmission system supplying the Boston area in that satisfactory system voltages may not be maintained during heavy load conditions.

Planned, under construction, or committed transmission lines for the future are:

Table 6A.7

FUTURE TRANSMISSION ADDITIONS *
New England Power Pool

<u>KV</u>	<u>Miles</u> <u>(1979-1983)</u>	<u>Miles</u> <u>(1984-1988)</u>
345	113	673

* Total Existing and Planned as of 12/31/88:

<u>KV</u>	<u>Miles</u>
230	444
345	2,325

* Based on NERC 9th Annual Review.

Table 6A.8

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
New England Power Pool

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	20075	20790	19921	21198	20550	21168
2. Peak Demand	14194	14822	14404	15072	14324	15278
3. Planned Reserves (1-2)	5881	5968	5517	6126	6226	5890
4. Planned Reserves (%) (3/2)x100	41.4	40.3	38.3	40.6	43.5	38.6
5. Net Transactions (Imports-Exports)	164	162	162	163	150	150
6. Total Capability (1+5)	20239	20952	20083	21361	20700	21318
7. Total Reserves (6-2)	6045	6130	5679	6289	6376	6040
8. Total Reserves (%) (7/2)x100	42.6	41.4	39.4	41.7	44.5	39.5
9. Scheduled Maintenance	-	-	-	-	-	-
10. Capability after Maintenance (6-9)	20239	20952	20083	21361	20700	21318
11. Reserves after Maintenance (10-2)	6045	6130	5679	6289	6376	6040
12. Reserves after Maintenance (%) (11/2)x100	42.6	41.4	39.4	41.7	44.5	39.5
13. Inoperable Capability <u>1/</u>	5043	4322	5775	4366	4841	4332
14. Available Capability (10-13)	15196	16630	14308	16995	15859	16986
15. Available Reserves (14-2)	1002	1808	-96	1923	1535	1708
16. Available Reserves (%) (15/2)x100	7.1	12.2	-0.7	12.8	10.7	11.2
17. Forced Outages	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	15196	16630	14308	16995	15859	16986
19. Actual Reserves (18-2)	1002	1808	-96	1923	1535	1708
20. Actual Reserves (%) (19/2)x100	7.1	12.2	-0.7	12.8	10.7	11.2

1/ Includes outages due to scheduled maintenance, inoperable, and forced.

Table 6A.9

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
New England Power Pool

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	20720	21429
2. Peak Demand	14190	16110
3. Planned Reserves (1-2)	6530	5319
4. Planned Reserves (%) (3/2)x100	46.0	33.0
5. Net Transactions (Imports-Exports)	625	548
6. Total Capability (1+5)	21345	21977
7. Total Reserves (6-2)	7155	5867
8. Total Reserves (%) (7/2)x100	50.4	36.4
9. Scheduled Maintenance	1203	242
10. Capability after Maintenance (6-9)	20142	21735
11. Reserves after Maintenance (10-2)	5952	5625
12. Reserves after Maintenance (%) (11/2)x100	41.9	34.9
13. Inoperable Capability	306	296
14. Available Capability (10-13)	19836	21439
15. Available Reserves (14-2)	5646	5329
16. Available Reserves (%) (15/2)x100	39.8	33.1
17. Forced Outages <u>2/</u>	-	-
18. Actual Capability after Forced Outages (14-17)	19836	21439
19. Actual Reserves (18-2)	5646	5329
20. Actual Reserves (%) (19/2)x100	39.8	33.1

1/ No delays anticipated in new units
since submittal of 1980 ERA-411.

2/ Information not reported.

Table 6A.10.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
New England Power Pool

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	20745	21779	21035	21955	22324	23115	22320	23109
2. Peak Demand	14210	16250	14400	16590	14630	16960	14910	17390
3. Planned Reserves (1-2)	6535	5529	6635	5365	7694	6155	7410	5719
4. Planned Reserves (%) (3/2)x100	46.0	34.0	46.1	32.3	52.6	36.3	49.7	32.9
5. Net Transactions (Imports-Exports)	618	458	621	601	624	603	627	583
6. Total Capability (1+5)	21363	22237	21656	22556	22948	23718	22947	23692
7. Total Reserves (6-2)	7153	5987	7256	5966	8318	6758	8037	6302
8. Total Reserves (%) (7/2)x100	50.3	36.8	50.4	36.0	56.9	39.8	53.9	36.2
9. Scheduled Maintenance	1836	133	531	913	479	133	2000	1000
10. Capability after Maintenance (6-9)	19527	22104	21125	21643	22469	23585	20947	22692
11. Reserves after Maintenance (10-2)	5317	5854	6725	5053	7839	6625	6037	5302
12. Reserves after Maintenance (%) (11/2)x100	37.4	36.0	46.7	30.5	53.6	39.1	40.5	30.5
13. Inoperable Capability	306	296	301	273	284	273	284	273
14. Available Capability (10-13)	19221	21808	20824	21370	22185	23312	20663	22419
15. Available Reserves (14-2)	5011	5558	6424	4780	7555	6352	5753	5029
16. Available Reserves (%) (15/2)x100	35.3	34.2	44.6	28.8	51.6	37.5	38.6	28.9
17. Forced Outages <u>2/</u>	-	-	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	19221	21808	20824	21370	22185	23312	20663	22419
19. Actual Reserves (18-2)	5011	5558	6424	4780	7555	6352	5753	5029
20. Actual Reserves (%) (19/2)x100	35.3	34.2	44.6	28.8	51.6	37.5	38.6	28.9

1/ Assumes no new unit delays.

2/ Information not available.

Table 6A.10.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985/89
New England Power Pool

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	23464	25409	25764	26542	25751	26416	25631	26416	25631	26986
2. Peak Demand	15180	17870	15530	18420	15920	18960	16300	19500	16660	20040
3. Planned Reserves (1-2)	8284	7539	10234	8122	9831	7456	9331	6916	8971	6946
4. Planned Reserves (%) (3/2)x100	54.6	42.2	65.9	44.1	61.8	39.3	57.2	35.5	53.8	34.7
5. Net Transactions (Imports-Exports)	608	381	410	181	210	180	209	180	209	180
6. Total Capability (1+5)	24072	25790	26174	26723	25961	26596	25840	26596	25840	27166
7. Total Reserves (6-2)	8892	7920	10644	8303	10041	7636	9540	7096	9180	7126
8. Total Reserves (%) (7/2)x100	58.6	44.3	68.5	45.1	63.1	40.3	58.5	36.4	55.1	35.6
9. Scheduled Maintenance 1/	-	-	-	-	-	-	-	-	-	-
10. Capability after Maintenance (6-9)	24072	25790	26174	26723	25961	26596	25840	26596	25840	27166
11. Reserves after Maintenance (10-2)	8892	7920	10644	8303	10041	7636	9540	7096	9180	7126
12. Reserves after Maintenance (%) (11/2)x100	58.6	44.3	68.5	45.1	63.1	40.3	58.5	36.4	55.1	35.6
13. Inoperable Capability	284	273	284	252	263	252	263	252	263	252
14. Available Capability (10-13)	23788	25517	25890	26471	25698	26344	25577	26344	25577	26914
15. Available Reserves (14-2)	8608	7647	10360	8051	9778	7384	9277	6844	8917	6874
16. Available Reserves (%) (15/2)x100	56.7	42.8	66.7	43.7	61.4	38.9	56.9	35.1	53.5	34.3
17. Forced Outages 1/	-	-	-	-	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	23788	25517	25890	26471	25698	26344	25577	26344	25577	26914
19. Actual Reserves (18-2)	8608	7647	10360	8051	9778	7384	9277	6844	8917	6874
20. Actual Reserves (%) (19/2)x100	56.7	42.8	66.7	43.7	61.4	38.9	56.9	35.1	53.5	34.3

1/ Information not available.

NEW YORK POWER POOL

Historical Perspective

New York Power Pool (NYPP) maintains an operating center near Albany, New York, for the eight major electric utility companies in New York State. Included in this group is a state system--Power Authority of the State of New York (PASNY). This Authority has developed several large hydro-electric generating stations, including Niagara Falls. Additionally, it has built some of the major transmission lines in the State, including a 765 KV line that is used for heavy imports of Canadian hydro-electric power. While the heavy industry is located in the northern portion of the State, the southern portion includes the country's most densely populated metropolitan area--New York City.

NYPP is the major importer of Canadian power for the eastern portion of the United States and provides a transmission link for transporting power to New England from the coal-burning plants of the West, and hydro-electric power from Canada. The State has a good mix of generating capacity divided between coal and nuclear generating units, as well as many small low-head hydro plants. However, due to the large amount of oil-fired capacity, the Region is dependent on imported oil for more than 1/3 of the electricity generated.

Tabulated below is a breakdown of the Pool's capability by fuel type for 1978, along with plant output for the years 1977 through 1979:

Table 6B.1

PERCENT GENERATION BY FUEL TYPE *
New York Power Pool

<u>Year</u>	<u>Nuclear</u>	<u>Hydro</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
1977	18	23	13	46	
1978	19	23	12	46	
1979	18	25	13	38	6

Table 6B.2

PERCENT INSTALLED CAPABILITY BY FUEL TYPE *
New York Power Pool

	<u>Year</u>	<u>Nuclear</u>	<u>Hydro</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>
(Summer)	1978	12.4	14.1	12.3	61.1	0.1

* Based on EIA Form 4 data and 1979 NERC Summary.

[For the purpose of these comparisons, the pump storage figures have been deleted as they generally require fossil fuel input for hydro output.]

The coal generating plants are located in the northern portion of the State, except for one jointly-owned plant, Homer City, located in Pennsylvania and owned by New York State Electric & Gas Co., and General Public Utilities (a system within the MAAC area).

The reduction in nuclear plant output in 1979 is due to prolonged outages of three units, namely: Fitzpatrick (PASNY); Indian Point #3 (PASNY); and Indian Point #2 (Con Edison)--all of which had outages for safety upgrading resulting from the lessons learned from Three Mile Island.

A comparison between total plant output and energy requirements for the 3-year is shown in the following table:

Table 6B.3

HISTORICAL GENERATION AND ENERGY REQUIREMENT *
New York Power Pool

<u>Year</u>	<u>Plant Output</u>		<u>Energy Requirement</u>	
	<u>GWH</u>	<u>% Change</u>	<u>GWH</u>	<u>% Change</u>
1977	112,538		113,483	
1978	113,124	+1	114,860	1.2
1979	105,245	-7	117,189	2.0

* Based on EIA-4 Form data and Form 12E-2 data.

This reduction in total output for 1979, though there was an increase in energy requirements, is a result of increased imports from Canada and the coal-burning utilities in the West. It resulted in the substantial decrease in the portion of the load allocated to oil-burning plants from 30 percent of total generation in 1978 to 21 percent in 1979.

The annual peak load and reserve margins are shown for the period 1977-1979 on Table 6B.8.

Tables 6B.3 and 6B.8 indicate total area energy requirements have continued to grow, but peak loads have decreased during the period shown. This decrease is due to mild weather and the increasing cost of electricity. As a result, each year the forecasts for load growth have been reduced. However, due to the long lead time required for building new capacity, today's apparently sizeable reserve margins are a result of the change in growth. Minimum planned reserves during the period range from 41 percent to 45 percent for the summer and as high as 64 percent for the winter. After considering net interchange and unavailable capacity, these numbers are reduced to as low as 15 percent for the summer and 21 percent for the winter.

Reserves were well above the established pool planned reserve criteria of approximately 22 percent. However, even with this sizeable capacity margin, some areas of the pool were not in as comfortable a position as the numbers might indicate. In a recent study to review the effects of a prolonged simultaneous outage of Indian Point Units 2 and 3, it was determined that New York City reliability would be questionable for a 1-year outage of this capacity.

Plant output, by fuel type, to meet the 1978 load requirements are tabulated below:

Table 6B.4

1978 NET DEPENDABLE CAPABILITY (MW) AND GENERATION
BY PRIME MOVER AND FUEL TYPE *

New York Power Pool

<u>Prime Mover</u>	<u>Fuel Type</u>	<u>Capability</u>		<u>Generation</u>	
		<u>MW</u>	<u>% Total</u>	<u>G W H</u>	<u>% Total</u>
Steam	Nuclear	3,602	12.1	21,694	18.4
Steam	Coal	3,484	11.6	18,723	15.9
Steam	Oil	13,991	47.1	51,183	43.5
Steam	Gas				
Hydro		4,035	13.6	26,080	22.1
Pump Storage		1,000	3.4	-568	-0.5
Gas Turbine	Oil	3,582	12.1	554	0.5
Gas Turbine	Gas	30	0.1	90	0.1
Combine Cycle	Oil				
Combine Cycle	Gas				
Other					
(Interchange)					

To produce this energy, fuel requirements were:

- 8.1 million tons of coal.
- 1.7 million barrels of distillate oil.
- 87.4 million barrels of residual oil.
- 1.1 million MCF natural gas.

* Based on 1979 NERC Summary of Peak Load and Capacity.

Sixteen and one-half percent (16.5%) of all of the residual oil used in the United States for electric generation is burned in the NYPP Region and 30 percent of all residual is burned in the NPCC Area, where almost all of the oil used is imported.

During 1979, there was an appreciable increase in the use of gas (65 percent of total plant output); however, the future of this fuel for utility use is uncertain. At present, FERC has granted an exemption only through the spring of 1980.

The Region is still heavily dependent on imported oil as a source of fuel, although every effort is being made to reduce its consumption. Even with an 8 percent reduction in oil-fired plant output, it was still 38 percent of the total energy generated within the State.

The percent of NYPP planned reserves are quite large for the present. The design criteria call for a pool reserve of 22 percent. To maintain this figure, the individual members must provide 18 percent reserve over its annual peak. The lower reserve is permitted because of load diversity between the various members. With a company reserve of 18 percent, a 5 percent voltage reduction would result in a 4 percent reduction in peak, while customer appeals could shave the peak an additional 3 percent. In addition to the reserves, the pool companies have five interruptable customer contracts that permit a total load reduction of 1,500 MW. This information is contained in Table 6.1.

The transmission system includes 1,075 miles of 230 KV lines; 2,109 miles of 345 KV lines; 5 miles of 500 KV lines; and 155 miles of 765 KV lines. There are no stability constraints in the transmission system, and usually the thermal ratings of the lines control the limits of transfers which are frequently heavy from North to South.

Environmental constraints preclude the use of any fuel except low sulfur oil in the densely populated southern metropolitan area of the State. This, coupled with an unusual New York City utility fuel use tax, makes it economically desirable to import as much energy into these regions as possible.

Additionally, several municipalities on Long Island are preferential customers of PASNY and, as such, are entitled to low cost hydro electric energy which must be wheeled from upstate. Much of the imported Canadian hydro power also follows this route. This movement of energy creates two problems:

First, in the area around Albany, close to the southern terminus of the Canadian-New York 765 KV line, there is heavy loading of

the transmission system during off-peak periods when Canadian energy is being imported. This causes a backing off of the base loaded coal-fired plants which could normally be displacing oil capacity at this time. Second, in the transmission corridor between Albany and New York City, normal transmission loading is sufficiently high so as to preclude prolonged outages of certain generating units; e.g. Indian Point. Any increase in Canadian hydro imports into this system would further aggravate this situation.

New York City has the highest electric rates in the contiguous United States, with Long Island not being much lower. As such, both the utilities serving these areas are experimenting with time-of-day rates. However, since the programs have been operating only a short time, there is no conclusive evidence of the system's success or failure.

Current Perspective

During the summer of 1980, the NYPP is expected to experience a peak demand of 21,230 MW. This would be an increase of 2.3 percent over the previous summer peak and an increase in growth as compared to 2.1 percent for the 1978-1979 period. The winter 1980-1981 peak is anticipated to be 19,870 MW, also an increase of 2.3 percent over the previous year. Total net energy for 1980 is expected to reach 117,814 GWH, a small increase of 0.5 percent over the previous year. Annual load factor based on these forecasts would be 63.2 percent. The summer planned capability to meet this load will be 30,467 MW. The loads, resources and margins anticipated for 1980 are listed in the Table 6B.9.

This table indicates a comfortable reserve margin after maintenance for 1980 that is higher than the Pool Agreement criteria. However, daily forced outages of approximately 14 percent of installed capacity are not included in the figures.

With estimated 1980 system requirements of 117,814 GWH, it is anticipated that the NYPP subregion will consume about 8.5 million tons of coal, over 88 million barrels of residual oil, and 280,000 barrels of distillate oil.

The transmission system for 1980 is adequate for system reliability and scheduled transfers of energy. As explained in the previous section, there is still the constraint of the Utica-Pleasant Valley bottleneck with regard to economy and oil conservation transfers. The critical unit in terms of voltage support is Oswego 6--an oil-fired unit due in mid-1980.

There are no other major projects scheduled for completion during 1980. Transmission lines scheduled for completion during the period include 0.2 miles of 345 KV lines and 46.9 miles of 115/138 KV lines.

Future Perspective

The 1981-1989 forecasts indicate a growth in the summer peak load averaging 2.0 percent annually. During the same time frame, the energy requirements are expected to increase at an average annual growth of 2.2 percent. Tables 6B.10.1 and 6B.10.2 show anticipated reserve margins for the period 1981-1989. These reserves exceed the NYPP Agreement criteria and indicate comfortable margins; however, that load could grow more rapidly than the modest rate indicated, and there will very likely be slippages in the construction schedule of various generating units. Indicated later in the report are slippages presently being experienced for projects under construction.

To meet the load increases projected, approximately 4,425 MW of new base load generating capacity has been scheduled. This will include 2,015 MW nuclear, and 2,410 MW coal-fired plants. The nuclear additions will increase the proportional share of capacity from 12 percent to 16 percent by 1988, and coal from 12 percent to 17 percent. The long range plans of the New York State Energy Office are committed to a future of coal rather than nuclear plants, and prohibition orders for several oil-fired plants in the State have already been issued by DOE. However, there is the question of the ability of the State rail transportation system to handle the required increased coal tonnage.

The New York State Energy Board, in its formal order on the State's first energy master plan of March 20th, opposed new nuclear plants at this time and proposed a State panel to evaluate nuclear power, including the potential impact of phasing down or eliminating existing plants. The objective of reducing oil use for the 1990 time frame cannot be fully achieved with this new plan. The State plan included oil savings from increased conservation and management, the conversion of 3,281 MW in thirteen existing oil-fired plants to coal, the addition of 271 MW from small hydro electric projects, the development of 397 MW by burning solid waste, and continued purchases of Hydro Quebec Power.

The following table indicates the proportion of capacity by fuel type for the years 1984 and 1988:

Table 6B.5

SUMMER PLANNED CAPABILITY BY PRIME MOVER AND FUEL TYPE *
New York Power Pool

<u>Prime Mover</u>	<u>Fuel Type</u>	<u>1984 % of Total</u>	<u>1988 % of Total</u>
Steam	Nuclear	14.3	16
Steam	Coal	14.0	17
Steam	Oil	44.1	39
Steam	Gas		
Hydro		12.9	12
Pumped Storage		3.2	6
Gas Turbine	Oil	11.3	10
Gas Turbine	Gas	0.1	0
Combined Cycle	Oil		
Combined Cycle	Gas		
Other		<u>0.1</u>	<u>0</u>
		100 %	100 %

* Based on 1979 NERC Summary of Projected Peak Load & Generating Capability, and ERA-411 Form.

To meet the 1989 plant output of 131,178 GWH will require almost 9 million tons of coal, 99 million barrels of residual oil, and 350,000 barrels of distillate oil. The 1988 plant output of 146,800 GWH will require over 10 million tons of coal, 100 million barrels of residual oil, and 420,000 barrels of distillate oil.

Table 6B.6 shows the major nuclear and coal-fueled units planned and under construction for the Region. The listing includes the slippage experienced for each of the units, indicating the probability of reduced reserves for future years should the forecast materialize as anticipated.

At present, no slippage is anticipated by the individual pool utilities from the dates shown in the table except for

Shoreham #1 which now has an anticipated in-service date of January 1983. This delay will require an additional 15 million barrels of residual oil for replacement energy from within the New York Power Pool.

The only critical transmission project is the installation of additional transmission capacity to overcome the Utica-Pleasant Valley bottleneck which limits future increases in Canadian hydro imports.

Table 6B.6

PLANNED MAJOR CAPACITY ADDITIONS *
New York Power Pool

<u>Utility</u>	<u>Plant Name</u>	<u>Name Plate Capacity</u>	<u>Original In-Service Date</u>	<u>In-Service Date as of April 1979</u>	<u>Present In-Service Date</u>
<u>N u c l e a r</u>					
NIMP	Nine Mile Pt # 2	1166	Apr 1979	Nov 1984	Nov 1986
POAS	Green Country	1277	Jun 1983	-	Cancelled
LOIL	Shoreham #1	849	Aug 1970	Dec 1980	May 1981
ORRU	Sterling #1	1195	Oct 1982	May 1988	Cancelled
LOIL	Jamesport # 1	1191	May 1981	-	Cancelled
LOIL	Jamesport #2	1191	May 1983	-	Cancelled
NEYE	New Haven #1	1250	May 1991	-	May 1992
NEYE	New Haven #2	1250	Mar 1993	-	May 1994
<u>C o a l</u>					
NEYE	Somerset (Cayuga #1)	850	Oct 1982	Nov 1984	Nov 1984
POAS	700 MW Fossil	760	Sep 1982	-	May 1987
LOIL & NEYE	Jamesport #1	800	May 1989	-	-

* Based on Form 12E-2.

The following table shows transmission lines which are planned, committed, or under construction:

Table 6B.7

PLANNED TRANSMISSION ADDITIONS *
New York Power Pool

<u>KV</u>	<u>Miles</u> <u>(1979-1983)</u>	<u>Miles</u> <u>(1984-1988)</u>
230	44	0
345	304	259
765	9	80

* Total Existing and Planned as of 12/31/88:

<u>KV</u>	<u>Miles</u>
230	1,119
345	2,662
500	5
765	244

* Based on NERC 9th Annual Review.

Table 6B.8

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
New York Power Pool

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	29728	30856	29435	31125	30032	31083
2. Peak Demand	21103	18838	20316	19598	20746	19417
3. Planned Reserves (1-2)	8625	12018	9119	11527	9286	11666
4. Planned Reserves (%) (3/2)x100	40.9	63.8	44.9	58.8	44.8	60.1
5. Net Transactions (Imports-Exports)	-130	-150	159	-150	668	-49
6. Total Capability (1+5)	29598	30706	29594	30975	30700	31034
7. Total Reserves (6-2)	8495	11868	9278	11377	9954	11617
8. Total Reserves (%) (7/2)x100	40.3	63.0	45.7	58.1	48.0	59.8
9. Scheduled Maintenance	-	-	-	-	-	-
10. Capability after Maintenance (6-9)	29598	30706	29594	30975	30700	31034
11. Reserves after Maintenance (10-2)	8495	11868	9278	11377	9954	11617
12. Reserves after Maintenance (%) (11/2)x100	40.3	63.0	45.7	58.1	48.0	59.8
13. Inoperable Capability <u>1/</u>	6434	5794	5841	8124	8264	8309
14. Available Capability (10-13)	23164	24912	23753	22851	22436	22725
15. Available Reserves (14-2)	2061	6074	3437	3253	1690	3308
16. Available Reserves (%) (15/2)x100	9.8	32.2	16.9	16.6	8.1	17.0
17. Forced Outages	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	23164	24912	23753	22851	22436	22725
19. Actual Reserves (18-2)	2061	6074	3437	3253	1690	3308
20. Actual Reserves (%) (19/2)x100	9.8	32.2	16.9	16.6	8.1	17.0

1/ Includes outages for scheduled maintenance, inoperable, and forced.

Table 6B.9

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
New York Power Pool

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	30467	31540
2. Peak Demand	21230	19870
3. Planned Reserves (1-2)	9237	11670
4. Planned Reserves (%) (3/2)x100	43.5	58.7
5. Net Transactions (Imports-Exports)	650	-100
6. Total Capability (1+5)	31117	31440
7. Total Reserves (6-2)	9887	11570
8. Total Reserves (%) (7/2)x100	46.6	58.2
9. Scheduled Maintenance	700	2200
10. Capability after Maintenance (6-9)	30417	29240
11. Reserves after Maintenance (10-2)	9187	9370
12. Reserves after Maintenance (%) (11/2)x100	43.3	47.2
13. Inoperable Capability	-	-
14. Available Capability (10-13)	30417	29240
15. Available Reserves (14-2)	9187	9370
16. Available Reserves (%) (15/2)x100	43.4	47.2
17. Forced Outages <u>2/</u>	-	-
18. Actual Capability after Forced Outages (14-17)	30417	29240
19. Actual Reserves (18-2)	9187	9370
20. Actual Reserves (%) (19/2)x100	43.3	47.2

1/ No delays anticipated in new units since submittal of 1980 ERA-411.

2/ Information not reported.

Table 6B.10.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
New York Power Pool

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	31252	32343	31277	32388	31327	32418	31321	33288
2. Peak Demand	21610	20310	22070	20800	22480	21200	22850	21630
3. Planned Reserves (1-2)	9642	12033	9207	11588	8847	11218	8471	11658
4. Planned Reserves (%) (3/2)x100	44.6	59.2	41.7	55.7	39.4	52.9	37.1	53.9
5. Net Transactions (Imports-Exports)	550	-8	650	-150	650	-150	650	-150
6. Total Capability (1+5)	31902	32335	31927	32238	31977	32268	31971	33138
7. Total Reserves (6-2)	10292	12025	9857	11438	9497	11068	9121	11508
8. Total Reserves (%) (7/2)x100	47.6	59.2	44.7	55.0	42.2	52.2	39.9	53.2
9. Scheduled Maintenance	1200	1300	1200	1300	1200	1300	1200	1300
10. Capability after Maintenance (6-9)	30702	31035	30727	30938	30777	30968	30771	31838
11. Reserves after Maintenance (10-2)	9092	10725	8657	10138	8297	9768	7921	10208
12. Reserves after Maintenance (%) (11/2)x100	42.1	52.8	39.2	48.7	36.9	46.1	34.7	47.2
13. Inoperable Capability <u>2/</u>	-	-	-	-	-	-	-	-
14. Available Capability (10-13)	30702	31035	30727	30938	30777	30968	30771	31838
15. Available Reserves (14-2)	9092	10725	8657	10138	8297	9768	7921	10208
16. Available Reserves (%) (15/2)x100	42.1	52.8	39.2	48.7	36.9	46.1	34.7	47.2
17. Forced Outages <u>2/</u>	-	-	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	30702	31035	30727	30938	30777	30968	30771	31838
19. Actual Reserves (18-2)	9092	10725	8657	10138	8297	9768	7921	10208
20. Actual Reserves (%) (19/2)x100	42.1	52.8	39.2	48.7	36.9	46.1	34.7	47.2

1/ Assuming no delays in projected units.

2/ Information unavailable.

Table 6B.10.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985/89
New York Power Pool

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	32230	33321	32271	34338	34974	35999	34936	36040	35709	36797
2. Peak Demand	23250	22070	23720	22550	24230	23100	24710	23630	25300	24260
3. Planned Reserves (1-2)	8980	11251	8551	11788	10744	12899	10226	12410	10409	12537
4. Planned Reserves (%) (3/2)x100	38.6	51.0	36.0	52.3	44.3	55.8	41.4	52.5	41.1	51.7
5. Net Transactions (Imports-Exports)	650	-150	650	-150	650	-150	650	-150	650	-150
6. Total Capability (1+5)	32880	33171	32921	34188	35624	35849	35586	35890	36359	36647
7. Total Reserves (6-2)	9630	11101	9201	11638	11394	12749	10876	12260	11059	12387
8. Total Reserves (%) (7/2)x100	41.4	50.3	38.8	51.6	47.0	55.2	44.0	51.9	43.7	51.1
9. Scheduled Maintenance <u>2/</u>	-	-	-	-	-	-	-	-	-	-
10. Capability after Maintenance (6-9)	32880	33171	32921	34188	35624	35849	35586	35890	36359	36647
11. Reserves after Maintenance (10-2)	9630	11101	9201	11638	11394	12749	10876	12260	11059	12387
12. Reserves after Maintenance (%) (11/2)x100	41.4	50.3	38.8	51.6	47.0	55.2	44.0	51.9	43.7	51.1
13. Inoperable Capability <u>2/</u>	-	-	-	-	-	-	-	-	-	-
14. Available Capability (10-13)	32880	33171	32921	34188	35624	35849	35586	35890	36359	36647
15. Available Reserves (14-2)	9630	11101	9201	11638	11394	12749	10876	12260	11059	12387
16. Available Reserves (%) (15/2)x100	41.4	50.3	38.8	51.6	47.0	55.2	44.0	51.9	43.7	51.1
17. Forced Outages <u>2/</u>	-	-	-	-	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	32880	33171	32921	34188	35624	35849	35586	35890	36359	36647
19. Actual Reserves (18-2)	9630	11101	9201	11638	11394	12749	10876	12260	11059	12387
20. Actual Reserves (%) (19/2)x100	41.4	50.3	38.8	51.6	47.0	55.2	44.0	51.9	43.7	51.1

1/ Assumes no new unit delays.

2/ Information unavailable.

SECTION XI.7

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

(SERC)

Southeastern Electric Reliability Council Area
Power Supply and Demand
1980-1989

Introduction

The Southeastern Electric Reliability Council (SERC) region includes all of the States of Alabama, Georgia, Florida, North Carolina, South Carolina and Tennessee and parts of Mississippi, Kentucky and Virginia. The SERC region represents about 10 percent of the nation's contiguous area but accounts for about 20 percent of the nation's electric energy.

Within SERC there are four subregional groups which coordinate their planning and operation. There is the Southern Subregion which includes all of Georgia, most of Alabama, the southeast one-quarter of Mississippi and the northwest corner of Florida; the Florida Subregion which covers the Florida Peninsula; the TVA Subregion which covers all of Tennessee and small parts of Alabama, Mississippi and Kentucky; and the VACAR Subregion which includes North Carolina, South Carolina and most of Virginia. Each of these subregions has their own unique characteristics which affects their electric bulk power supply.

The TVA Subregion is a definite winter peaking area while the Southern Subregion is a definite summer peaking region. The Florida Subregion can peak in either summer or winter as can the VACAP Subregion. Due to the proximity of the Southern, TVA, and VACAP to the Appalachian coal mines the fuel mixes of these subregions are similar. These subregions are heavily dependent upon coal for electric power generation. Most of the generating capacity in the Florida Subregion was originally designed to burn natural gas as a primary fuel with oil as an alternate fuel. The sudden attrition of natural gas supplies coupled with the expiration of natural gas supply contracts has left the Florida Subregion heavily dependent upon high cost oil for electric generation.

Geographical location has not only affected the fuel mixes but has influenced the pattern of transmission development within and between each of these subregions. The TVA Subregion is very close to the geographical center of the seven eastern interconnected reliability council areas and is perhaps the key link between these areas. Consequently, a high capacity 500 kV transmission network has been developed in the TVA Subregion. There is a significant amount of 500 kV in the VACAR Subregion, some 500 kV in the Southern Subregion and isolated segments of 500 kV in the Florida Subregion. Therefore, the opportunities to interconnect at 500 kV tend to diminish with distance from the TVA Subregion, particularly in a southward direction. Nevertheless, it is generally important for each subregion to maintain an intra-regional transmission import, capability equal to the composite spinning reserve for the total council area, over and above firm scheduled purchases and sales. The current spinning reserve of the SERC is approximately 3,500 MW.

Generating unit forced outages varied from a low average of 12% of peak demand in the Florida Subregion to a high average of 21% in VACAR and TVA Subregions during 1977 through 1979 period. Generating unit forced outages averaged 16% of the peak demand in the Southern Subregion. Generating unit maintenance outages during the peak season varied from a low average of 3% in the Southern Subregion to a high average of 16% in the Florida Subregion during this period. Maintenance outages in the TVA and VACAR Subregions averaged 6 and 10%, respectively.

Assessment Methodology

The assessments in this report are not analytical but are statistical and are based on information reported to the Department of Energy on Forms 12E-2, Form 1 and ERA-411 by the electric utilities, information developed through personal contacts with electric utility officials and from information reported by the electric utilities to the National Electric Reliability Council.

A three-part examination entitled Historical Perspective, Current Perspective and Future Perspective is included in the report for each subregion. The Historical Perspective reviews the 1977 through 1979 period, the Current Perspective covers the near-term 1980 situation and the Future Perspective covers the 1981-1989 period.

Each region's bulk power supply was assessed based essentially on five statistical parameters as follows:

1. Load Growth - annual energy, seasonal peak demand and annual load factor in percent.
2. Planned Reserves - in percent of peak demand.
3. Reserve after maintenance - in comparison to the region's operating criteria.
4. Fuel Mix - in percent of total generating capacity.
5. Transmission Capacity - in MW miles per MW of generating capacity as well as emergency import capability in percent of peak demand.

Table 7.1 summarizes representative portions of the five statistical parameters by SERC Subregions. A list of the reporting entities covered by each subregion is shown on attached Table 7.2.

TABLE 7.1

Load Growth, Planned and Actual Reserve, Fuel Mix
and Transmission Capacity

SERC Region

	<u>Florida</u>	<u>Southern</u>	<u>TVA</u>	<u>VACAP</u>
1. Electric Energy Growth in % <u>1/</u>				
1977 - 1979	4.5	3.0	3.7	2.5
1980 - 1989	4.4	4.1	3.9	4.8
2. Lowest Planned/Total Reserves in %				
1977 - 1979 <u>2/</u>	30.4	8.0	15.8	24.2
1980 - 1989 <u>3/</u>	20.2	23.7	26.9	19.2
3. Lowest Actual Reserve in MW				
1977 - 1979 <u>4/</u>	974	1,083	63	(2,706)
1980 - 1989	1,120	2,577	1,107	(427)
4. Non-oil/gas Capacity in %				
1978	22.7	86.3	91.4	79.6
1980	23.8	87.7	92.2	81.1
1984	30.5	89.5	93.5	84.9
1989	44.0	92.0	94.7	87.3
5a. Transmission in MW-miles/MW				
Total as of (1977 - 1979)	70 <u>5/</u>	150 <u>6/</u>	110 <u>7/</u>	115 <u>6/</u>
Incremental from 1980 - 1989	95	110	80	124
5b. Emergency Import Capacity in %				
1980	1.5	18.0	30.2	27.8
1984	1.3	16.4	40.7	20.3

-
- 1/ Figure 7.1 is a graphical summary of the actual and forecast electric energy use by SERC Subregions.
- 2/ Does not include historical purchases and sales because these included emergency transfers.
- 3/ Includes firm scheduled purchases and sales.
- 4/ Emergency transfers are included in the historical available reserve figures.
- 5/ As of 1977.
- 6/ As of 1978.
- 7/ As of 1979.

Florida SubregionHistorical Perspective

Until recently, the Florida Subregion was a vigorous electrical energy and peak demand growth area. As late as 1974, annual electric energy use was predicted to increase at an average annual rate of 10.0 percent and annual peak demand was forecasted to increase at an average annual rate of 10.6 percent, over the next ten years. Both electric energy use and electric demand growth have moderated considerably since that time. Price of electricity may be a factor in this reduction. The cost of electricity production (\$1979) in Florida ranged from approximately 50 to 60 mills/kWh. Econometric estimates indicate that for each 1 percent rise in the real price of electricity a 0.4 percent to 0.8 percent decrease in demand for electricity will result in Florida. Actual average annual growth in net energy for load for 1977 through 1979 was 4.5 percent. Over this period, the summer peak demand increased at a rate of 3.7 percent and the winter peak demand grew at a rate of 3.4 percent. Table 7A.1 shows actual figures for each of these years along with computed average load factor.

TABLE 7A.1

Actual Annual Net Energy for Load, Summer and Winter Peak Demands and Load Factors 1/

Florida Coordinating Group Region

<u>Item</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy in GWH	79,717	84,314	87,017
Summer Peak Demand in MW	15,444	16,014	16,599
Winter Peak Demand in MW <u>2/</u>	16,965	17,131	18,142
Annual Load Factor in %	53.6	56.2	54.8

Actual mid-period (1978) summer generating capacity by fuel type and resulting 1978 actual energy production is shown on Table 7A.2. Oil and natural gas accounted for 69 percent of electric generation in the Florida Peninsula in 1978.

1/ Source - Form No. 12E-2

2/ Winter period for each year includes December of that year plus January and February of the following year.

TABLE 7A.2

Actual 1978 Summer Generating Capacity by Fuel Type
Florida Coordinating Group Region

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>Capacity</u>		<u>Generation</u>	
		<u>MW</u>	<u>% of Total</u>	<u>GWh</u>	<u>% of Total</u>
Steam	Nuclear	2,876	13.2	15,763	18.5
Steam	Coal	2,012	9.3	10,369	12.2
Steam	Oil	12,299	56.6	40,468	47.6
Steam	Gas	0	0.0	15,322	18.0
Hydro	Water	36	0.2	224	0.3
Pumped Storage	Water	0	0.0	0	0.0
Gas Turbine	Oil	4,035	18.6	1,607	1.9
Gas Turbine	Gas	0	0.0	497	0.6
Combined Cycle	Oil	460	2.1	706	0.8
Combined Cycle	Gas	0	0.0	109	0.1
Other		<u>0</u>	<u>0.0</u>	<u>0</u>	<u>0.0</u>
Total		21,718	100.0	85,065	100.0

A total of 144 million Mcf of natural gas was used during 1978 to produce electricity in the Florida Subregion. Of this amount, 112 million Mcf or 78 percent was supplied under firm contracts and the rest was interruptible. Two natural gas supply contracts for a total of 140 million cubic feet per day expired in June 1979. This is expected to reduce natural gas supply by about 35 percent for 1980. The remaining major natural gas supply contracts will expire by 1988.

There are currently four nuclear generating units 1/ in operation at the present time in Florida and one more unit 2/ is scheduled for operation in the next ten years.

A total of 76 million barrels of oil were used in the Florida Subregion during 1978 and almost all of this (96 percent) was residual oil. This amount was about 12 percent of that used by all electric utilities in the United States during 1978.

1/ Crystal River No. 3 (782/807 MW), St. Lucie No. 1 (777/795 MW), Turkey Point No. 3 (666/696 MW), and Turkey Point No. 4 (666/696 MW).

2/ St. Lucie No. 2 (795/812 MW).

XI.7.6

The Florida Peninsula utilities maintain an operating reserve equal to twice the size of the largest generating unit. One-half of this is to be spinning at all times and the remainder is to be available within thirty minutes. The largest generating unit in the Florida Subregion is 800 MW. There is no criteria covering the amount of planned reserve, but 20 to 25 percent of peak demand is generally considered adequate by Florida electric utilities. Tables 7A.3 through 7A.5 give the actual reserve situations that occurred in the Florida Subregion for 1977 through 1979 for each of the three summer months (June, July and August) and the three winter months (December, January and February). Planned reserve exceeded 20 percent of peak demand during each of the eighteen historical peak periods. The lowest planned reserve was 30.4 percent and occurred in February 1980. Actual reserve, however, did not meet the operating reserve requirement of 1,600 MW on two occasions. The lowest available reserve was 974 MW and occurred in January 1979.

Transmission in Florida has historically been installed on the basis of service territory. There has been no allocation of costs or sharing of costs based on benefits received. Although there are isolated segments of 500 kV in operation, the workhorse transmission voltage is 230 kV. In 1977 there was about 1.5 million megawatt-miles of transmission lines in service consisting of about 230 miles of 500 kV line, about 3,000 miles of 230 kV line and about 4,500 miles of 115 kV and 138 kV lines. This resulted in a transmission capacity to generating capacity ratio of about 70 MW-miles per MW.

Until December 1979 the Florida Subregion was interconnected to the Southern Subregion by one 230 kV line and several 115 kV lines having a combined import capability of 300 MW. This represented about 1.9 percent of the 1978 summer peak demand. An additional 230 kV tie was installed in December 1979 which is expected to increase the import capability to about 600 MW for 1980.

There have been continuing stability and transient voltage problems at the Florida-Southern interface that cannot be resolved at the 230 kV voltage level due to the fact that the electrical centers of these respective areas are about 400 miles apart. "Coal-by-wire" transfers to Florida greatly aggravated these problems to where there were approximately 10 load shedding incidents in the Florida Subregion during 1979.

Florida Subregion systems have instituted a unique broker energy exchange arrangement which has produced significant dollar savings to the participants. During 1979 the energy broker saved over \$22 million. Pool dispatch is currently being evaluated as a further possible step to increase operation savings.

Current Perspective

The 1980 summer peak demand of 17,534 is expected to occur in the Florida Subregion in August. This forecast represents a 5.6 percent increase over the actual 1979 summer peak demand. Although the summer peak demand is predicted to occur in August, the month of June can be more critical in the Florida Subregion because the peak can potentially occur in June at a time when scheduled maintenance and overhaul of generating equipment is still relatively heavy. Should this occur, reserve after maintenance could be reduced to about 2,500 MW this June. Otherwise reserve after maintenance should exceed 3,000 MW during the 1980 summer season.

No additional new generating units are scheduled for operation prior to the 1980 summer season. The Crystal River No. 3 nuclear generating unit, rated at 782 MW, underwent modifications and refueling in late February and is due back by mid-May. Should this unit not return as expected, June operating reserve would be close to the Florida Subregion's minimum operating criteria. The Anclote Plant (1,007 MW) has an environmental permit which restricts its operation when water temperature is high. The unavailability of some of this plant's capability for environmental reasons could also affect the reserve situation for this summer.

The projected 1980 winter peak demand is expected to increase by 7.8 percent over the 1979 winter peak demand, to 19,552 MW. Traditionally, the winter peak forecasts in the Florida Subregion are based on extremely cold conditions which typically occur only about once every four years. Should this forecast materialize as estimated, reserve after maintenance is expected to exceed 3,900 MW. This, however, is contingent upon successful completion of the Martin No. 1 generating unit, rated at 787 MW, prior to the winter peak season. Even without the Martin No. 1 unit, reserve for the 1980 winter season should be adequate. Table 7A.6 gives the current reserve picture for the three summer months and three winter months for 1980.

The interconnection import capability of the Florida Subregion, over and above scheduled purchases and sales, is about 300 MW. This is 1.5 percent of the projected 1980 winter peak demand.

The Florida Subregion has a curtailment program whereby a total of 797 MW or 4.1 percent of the projected 1980 winter peak demand could be reduced manually in the event of an extreme emergency. Of this amount, relief of 200 MW can be achieved through a 5 percent voltage reduction, interruption of interruptible contract load can bring 552 MW relief and curtailment of non-essential utility load can result in 45 MW load reduction.

Future Perspective

The Florida Subregion is forecasting their annual electric energy use to increase from 92,723 GWH in 1980 to 136,897 GWH in 1989. This is an average annual growth rate of 4.4 percent and is consistent with their electric energy growth rate during the past three years. Their summer peak demand is estimated to grow at an average annual rate of 4.7 percent, from 17,534 MW in 1980 to 26,459 MW in 1989. Their winter peak demand is expected to increase from 19,552 MW in 1980 to 29,166 MW in 1989, an average annual growth rate of 4.5 percent. Annual load factor is expected to remain in the 53 to 54 percent range during the 1980 through 1989 period.

Florida Subregion's load forecast for the 1980 through 1984 period is higher than either the past three year average or the overall future ten year average. The summer peak demand for the 1980 through 1984 period is predicted to increase at an average annual rate of 5.1 percent and the winter peak is estimated to increase at 4.9 percent.

While Florida Subregion's load forecasts may be optimistic in view of present economic conditions, the timing of future generating unit additions should be unaffected by this since it is considerably more important to aim at changing the fuel mix as rapidly as possible rather than aiming to meet load growth alone.

Almost all of the future generating capacity additions in the Florida Subregion (see attached Table 7A.8 for details) are planned to be coal-fired. The impact of these additions on the overall generating capacity fuel mix is shown in Table 7A.7 for mid-year 1980, 1984 and 1989, respectively. The amount of nuclear and coal-fired generating capacity expected to be in service by 1989 represents a threefold increase over that which existed in 1978. Nuclear and coal-fired generating capacity is expected to represent 43.4 percent of the total generating capacity by 1989 compared to 22.5 percent for 1978.

Possibly the least capital intensive option available to accelerate the reduction of oil use for generation in the Florida Subregion is the construction of extra-high voltage transmission between the Florida and Southern Subregions to increase coal-by-wire transfers into the Florida Peninsula. A fully integrated transmission network consisting of about 420 miles of additional 500 kV lines in Florida would be required to implement this strategy in a reliable manner.^{1/} Essentially, two parallel 500 kV circuits are needed. One circuit, already in the planning stage, when completed, would extend from Plant Hatch in southeast Georgia down the east coast of Florida to the Midway Substation north of Miami. A second circuit, which is not currently planned, from Tifton, Georgia needs to be extended in south central Georgia to the central Florida area. These circuits would connect the isolated 500 kV segments in Florida to the integrated 500 kV system in the rest of the SERC region. Oil savings of about 10 million barrels per year at an average annual investment cost of about \$10 per barrel saving appear possible with this system.^{1/} It is estimated that the reliability of the Florida Subregion would also be improved by an estimated 20 to 30 percent and the transmission import capability would be increased to between 2,500 MW and 3,000 MW when fully implemented.^{2/}

Since construction of these interconnections will be staged, reliability could be lessened during the implementation phase because weaker lower voltage lines will be interfacing higher voltage systems within the Florida Peninsula. This is particularly true following completion of the first leg of the east coast line from Plant Hatch to Jacksonville in mid-1983. The east coast 500 kV line is scheduled for completion between 1985 to 1987. Legislation is being considered in Florida to change the transmission certification process from a county-by-county to a one-stop state level basis. This is imperative for prompt construction of these lines and facilities.

A total of 40 miles of 115 kV and 138 kV lines, 910 miles of 230 kV lines and 740 miles of 500 kV lines are planned for installation between 1980 and 1989. This represents a transmission capacity addition of about 1.1 million MW-miles. The net generating capacity additions for this same period are about 11,600 MW resulting in a transmission to generating capacity additions ratio of 95 MW miles per MW. This is a commendable increase in transmission capacity relative to generation capacity but is possibly short of what is needed by virtue of the fact that the present transmission design is so far below what is needed.

Electric region's ten-year baseline projections of generating capacity, seasonal peak demand and reserve margins are shown on Table 7A.9. Total reserve is expected to exceed 20 percent of peak demand during all of the next eighteen peak load seasons between 1981 and 1989.

^{1/} Alternatives Available to Reduce Oil Consumption by Florida's Electric Utilities (October 1979, pp. 139-140). Florida Power Coordinating Group.

^{2/} ERA Atlanta Field Office Study.

The Florida Subregion does not plan to add generating units of any greater size during this period than already exists. This will limit their single contingency generating unit liability to about 800 MW and double contingency generating unit loss to about 1,600 MW. Reserve after taking into account scheduled maintenance is expected to exceed 3,400 MW during the next foreseeable eight peak periods between 1981 and 1984.

The Florida Peninsula electric utilities, during the past year were able to arrest the slippage of new generating unit planned in-service date schedules. During the past year, major coal-fired generating unit installation dates slipped only 571 MW-months between 1981 and 1984 and 5,280 MW-months between 1985 and 1989. The net effect is an estimated increase in oil use of about 6 million barrels. There were some significant advances of some schedules but these were largely offset by a two-year delay of the Martin No. 3 generating unit from 1985 to 1987 (16,800 MW-months). Every effort should be made to accelerate and return this unit to its 1985 in-service date. Most of the generating unit delays were made for financial reasons according to statements by the utilities involved.

FIGURE 7.1

TABLE 7.2

Reporting Entities by SERC Subregion
Florida Subregion

Florida Power Corporation
Florida Power and Light Company
Fort Pierce Utilities Authority
City of Gainesville
City of Homestead
Jacksonville Electric Authority
Lake Worth Utilities Authority
City of Lakeland
New Smyrna Beach Utilities Commission
Orlando Utilities Commission
Sebring Utilities Commission
Seminola Electric Cooperative
Southeastern Power Administration
City of Tallahassee
Tampa Electric Company
City of Vero Beach

Southern Subregion

Alabama Electric Cooperative, Inc.
Alabama Power Company
Crisp County Power Commission
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Savannah Electric and Power Company
Southeastern Power Administration
South Mississippi Electric Power Assn.

TVA Subregion

Nantahala Power and Light Company
Tapoco, Inc.
Tennessee Valley Authority

VACAR Subregion

Carolina Power and Light Company
Duke Power Company
South Carolina Electric and Gas Company
South Carolina Public Service Authority
Southeastern Power Administration
Virginia Electric and Power Company
Yadkin, Inc.

Table 7A.3

HISTORICAL CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1977 Summer			1977/1978 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	20,485	20,470	20,726	22,600	22,943	22,943
(2) Peak Demand (MW)	15,444	14,924	14,447	14,688	16,238	16,965
(3) Planned Reserve (MW) (1-2)	5,041	5,546	6,279	7,912	6,705	5,978
(4) Planned Reserve (%) (3÷2) x 100	32.6	37.2	43.5	53.9	44.3	35.2
(5) Net Transactions <u>1/</u> (MW)	108	218	483	(11) <u>2/</u>	(17) <u>2/</u>	58
(6) Total Capability (MW) (1+5)	20,593	20,688	21,209	22,589	22,926	23,001
(7) Total Reserve (MW) (6-2)	5,149	5,764	6,762	7,901	6,688	6,036
(8) Total Reserve (%) (7÷2) x 100	33.3	38.6	46.8	53.8	41.2	35.6
(9) Scheduled Maintenance (MW)	1,914	1,941	1,389	2,007	1,937	1,660
(10) Capability after Maintenance (MW) (6-9)	18,679	18,747	19,820	20,582	20,989	21,341
(11) Reserve after Maintenance (MW) (10-2)	3,235	3,823	5,373	5,894	4,751	4,376
(12) Reserve after Maintenance (%) (11÷2) x 100	21.0	25.6	37.2	40.1	29.3	25.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	18,679	18,747	19,820	20,582	20,989	21,341
(15) Available Reserve (MW) (14-2)	3,235	3,823	5,373	5,894	4,751	4,376
(16) Available Reserve (%) (15÷2) x 100	21.0	25.6	37.2	40.1	29.3	25.8
(17) Forced Outages (F.O.) (MW)	1,610	1,260	1,771	2,536	2,232	2,564
(18) Available Capability after F.O. (MW) (14-17)	17,069	17,487	18,049	18,046	18,757	18,777
(19) Actual Reserve (MW) (18-2)	1,625	2,563	3,602	3,358	2,519	1,812
(20) Actual Reserve (%) (19÷2) x 100	10.5	17.2	24.9	22.9	15.5	10.7

1/ Net Transactions = Purchases - Sales

2/ () denotes negative number

Table 7A.4

HISTORICAL CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1978 Summer			1978/1979 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	22,155	22,163	22,155	23,423	23,700	23,333
(2) Peak Demand (MW)	15,685	15,698	16,014	13,711	16,724	17,131
(3) Planned Reserve (MW) (1-2)	6,470	6,465	6,141	9,712	6,976	6,202
(4) Planned Reserve (%) (3-2) x 100	41.3	41.2	38.6	70.8	41.7	36.2
(5) Net Transactions <u>1/</u> (MW)	270	150	148	331	83	172
(6) Total Capability (MW) (1+5)	22,425	22,313	22,303	23,754	23,783	23,505
(7) Total Reserve (MW) (6-2)	6,740	6,615	6,289	10,043	7,059	6,374
(8) Total Reserve (%) (7-2) x 100	43.0	42.1	39.3	73.3	42.2	37.2
(9) Scheduled Maintenance (MW)	2,484	2,123	2,189	5,444	2,765	2,169
(10) Capability after Maintenance (MW) (6-9)	19,941	20,190	20,144	18,310	21,018	21,336
(11) Reserve after Maintenance (MW) (10-2)	4,256	4,492	4,100	4,599	4,294	4,205
(12) Reserve after Maintenance (%) (11-2) x 100	27.1	28.6	25.6	33.5	25.7	24.6
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	19,941	20,190	20,144	18,310	21,018	21,336
(15) Available Reserve (MW) (14-2)	4,256	4,492	4,100	4,599	4,294	4,205
(16) Available Reserve (%) (15-2) x 100	27.1	28.6	25.6	33.5	25.7	24.6
(17) Forced Outages (F.O.) (MW)	1,974	2,229	2,293	1,514	3,320	2,384
(18) Available Capability after F.O. (MW) (14-17)	17,967	17,961	17,821	16,796	17,698	18,952
(19) Actual Reserve (MW) (18-2)	2,282	2,263	1,807	3,085	974	1,821
(20) Actual Reserve (%) (19-2) x 100	14.6	14.4	11.3	22.5	5.8	10.

1/ Net Transactions = Purchases - Sales

Table 7A.5

HISTORICAL CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1979 Summer			1979/1980 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	22,546	22,546	22,536	23,330	23,286	23,651
(2) Peak Demand (MW)	16,180	16,599	16,470	13,884	16,080	18,140
(3) Planned Reserve (MW) (1-2)	6,366	5,947	6,066	9,446	7,206	5,511
(4) Planned Reserve (%) $(3 \div 2) \times 100$	39.3	35.8	36.8	68.0	44.8	30.4
(5) Net Transactions $1/$ (MW)	344	296	171	457	155	617
(6) Total Capability (MW) (1+5)	22,890	22,842	22,707	23,787	23,441	24,268
(7) Total Reserve (MW) (6-2)	6,710	6,243	6,237	9,903	7,361	6,128
(8) Total Reserve (%) $(7 \div 2) \times 100$	41.5	37.6	37.9	71.3	45.8	33.8
(9) Scheduled Maintenance (MW)	2,034	1,976	1,846	3,309	3,020	1,686
(10) Capability after Maintenance (MW) (6-9)	20,856	20,866	20,861	20,478	20,421	22,582
(11) Reserve after Maintenance (MW) (10-2)	4,676	4,267	4,391	6,594	4,341	4,442
(12) Reserve after Maintenance (%) $(11 \div 2) \times 100$	28.9	25.7	26.7	47.5	27.0	24.5
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	20,856	20,866	20,861	20,478	20,421	22,582
(15) Available Reserve (MW) (14-2)	4,676	4,267	4,391	6,594	4,341	4,442
(16) Available Reserve (%) $(15 \div 2) \times 100$	28.9	25.7	26.7	47.5	27.0	24.5
(17) Forced Outages (F.O.) (MW)	3,123	1,629	1,783	2,195	1,583	2,275
(18) Available Capability after F.O. (MW) (14-17)	17,733	19,237	19,078	18,283	18,838	20,307
(19) Actual Reserve (MW) (18-2)	1,553	2,638	2,608	4,399	2,758	2,167
(20) Actual Reserve (%) $(19 \div 2) \times 100$	9.6	15.9	15.8	31.7	17.2	12.0

$1/$ Net Transactions = Purchases - Sales

Table 7A.6

CURRENT CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1980 Summer			1980/1981 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	21,851	21,851	21,851	24,177	24,281	24,516
(2) Peak Demand (MW)	16,957	17,486	17,534	16,093	19,552	18,800
(3) Planned Reserve (MW) (1-2)	4,894	4,365	4,317	8,084	4,729	5,716
(4) Planned Reserve (%) $(3 \div 2) \times 100$	28.9	25.0	24.6	50.2	24.2	30.4
(5) Net Transactions 1/ (MW)	265	265	265	265	265	265
(6) Total Capability (MW) (1+5)	22,116	22,116	22,116	24,442	24,546	24,781
(7) Total Reserve (MW) (6-2)	5,159	4,630	4,582	8,349	4,994	5,981
(8) Total Reserve (%) $(7 \div 2) \times 100$	30.4	26.5	26.1	51.9	25.5	31.8
(9) Scheduled Maintenance (MW)	2,075	1,287	998	2,432	1,052	1,036
(10) Capability after Maintenance (MW) (6-9)	20,041	20,829	21,118	22,010	23,494	23,745
(11) Reserve after Maintenance (MW) (10-2)	3,084	3,343	3,584	5,917	3,942	4,945
(12) Reserve after Maintenance (%) $(11 \div 2) \times 100$	18.2	19.1	20.4	36.8	20.2	26.3
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	20,041	20,829	21,118	22,010	23,494	23,745
(15) Available Reserve (MW) (14-2)	3,084	3,343	3,584	5,917	3,942	4,945
(16) Available Reserve (%) $(15 \div 2) \times 100$	18.2	19.1	20.4	36.8	20.2	26.3
(17) Forced Outages (F.O.) (MW) 2/	1,964	1,964	1,964	2,289	2,289	2,289
(18) Available Capability after F.O. (MW) (14-17)	18,077	18,865	19,154	19,721	21,205	21,456
(19) Actual Reserve (MW) (18-2)	1,120	1,379	1,620	3,628	1,653	2,656
(20) Actual Reserve (%) $(19 \div 2) \times 100$	6.6	7.9	9.2	22.5	8.5	14.1

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the
 ERA Field Office Staff

XI.7.16

TABLE 7A.7

Mid-Year Generating CapacityFlorida Coordinating Group Region

Unit-Fuel Type	1980		1984		1989	
	<u>MW</u>	<u>% of Total</u>	<u>MW</u>	<u>% of Total</u>	<u>MW</u>	<u>% of Total</u>
ST-Nuc	2,903	12.8	3,698	13.8	3,698	11.0
ST-Coal	2,443	10.8	4,357	16.3	10,880	32.4
ST-Oil	12,477	55.1	13,493	50.3	13,657	40.7
ST-Gas	0	0.0	0	0.0	0	0.0
Hydro	36	0.2	44	0.2	44	0.1
PS	0	0.0	0	0.0	0	0.0
GT-Oil	4,035	17.8	4,393	16.4	4,404	13.1
GT-Gas	0	0.0	0	0.0	0	0.0
CC-Oil	702	3.1	702	2.6	702	2.1
CC-Gas	30	0.2	30	0.1	30	0.1
Other	<u>0</u>	<u>0.0</u>	<u>90</u>	<u>0.3</u>	<u>170</u>	<u>0.5</u>
Total	22,626	100.0	26,807	100.0	33,585	100.0

TABLE 7A.8

Major Future Generating Unit In-Service Dates
Florida Coordinating Group Region

<u>Unit Designation</u>	<u>Capacity in MW</u>	<u>Fuel Type</u>	<u>As of 4/79</u>	<u>As of 4/80</u>	<u>Change in MW-months</u>
Martin No. 1	775	Oil	11/80	11/80	0
Deerhaven No. 2	235	Coal	1/81	2/81	235
Martin No. 2	775	Oil	11/81	11/81	0
McIntosh No. 3	334	Coal	11/81	10/81	(334)
Crystal River No. 4	670	Coal	12/82	12/82	0
St. Lucie No. 2	812	Nuc.	11/83	11/83	0
Seminole No. 1	600	Coal	5/83	5/83	0
Crystal River No. 5	670	Coal	5/84	6/84	670
Big Bend No. 4	417	Coal	3/85	3/85	0
Seminole No. 2	600	Coal	5/85	5/85	0
FLPL/JACO Joint No. 1	600	Coal	11/87	12/85	(13,800)
LALW/ORLA Joint No. 1	350	Coal	5/87	5/86	(4,200)
Osceola No. 1	660	Coal	10/85	6/86	5,280
Osceola No. 2	660	Coal	10/87	10/87	0
FLPL/JACO Joint No. 2	600	Coal	6/88	6/87	(7,200)
Martin No. 3	700	Coal	11/85	11/87	16,800
Martin No. 4	700	Coal	11/87	11/88	8,400

Table 7A.9

FUTURE CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	24,276	25,859	24,797	25,831	26,789	27,976	26,807	28,614
(2) Peak Demand (MW)	18,489	20,554	19,580	21,706	20,528	22,497	21,441	23,734
(3) Planned Reserve (MW) (1-2)	5,787	5,305	5,217	4,125	6,261	5,479	5,366	4,880
(4) Planned Reserve (%) (3÷2) x 100	31.3	25.8	26.6	19.0	30.5	24.4	25.0	20.6
(5) Net Transactions 1/ (MW)	215	215	215	250	250	250	250	250
(6) Total Capability (MW) (1+5)	24,491	26,074	25,012	26,081	27,039	28,226	27,057	28,864
(7) Total Reserve (MW) (6-2)	6,002	5,520	5,432	4,375	6,511	5,729	5,616	5,130
(8) Total Reserve (%) (7÷2) x 100	32.5	26.9	27.7	20.2	31.7	25.5	26.2	21.6
(9) Scheduled Maintenance (MW)	1,393	1,570	1,156	890	1,269	859	1,094	817
(10) Capability after Maintenance (MW) (6-9)	23,098	24,504	23,856	25,191	25,770	27,367	25,963	28,047
(11) Reserve after Maintenance (MW) (10-2)	4,609	3,950	4,276	3,485	5,242	4,870	4,522	4,313
(12) Reserve after Maintenance (%) (11÷2) x 100	24.9	19.2	21.8	16.1	25.5	21.7	21.1	18.2
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	23,098	24,504	23,856	25,191	25,770	27,367	25,963	28,047
(15) Available Reserve (MW) (14-2)	4,609	3,950	4,276	3,485	5,242	4,870	4,522	4,313
(16) Available Reserve (%) (15÷2) x 100	24.9	19.2	21.8	16.1	25.5	21.7	21.1	18.2
(17) Forced Outages (F.O.) (MW) 2/	1,964	2,289	1,964	2,289	1,964	2,289	1,964	2,289
(18) Available Capability after F.O. (MW) (14-17)	21,134	22,215	21,892	22,902	23,806	25,078	23,999	25,758
(19) Actual Reserve (MW) (18-2)	2,645	1,661	2,312	1,196	3,278	2,581	2,558	2,024
(20) Actual Reserve (%) (19÷2) x 100	14.3	8.1	11.8	5.5	16.0	11.5	11.9	8.5

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the
ERA Field Office Staff.

Table 7A.9

FUTURE CAPABILITY AND RESERVE MARGINS
FLORIDA COORDINATING GROUP REGION

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	28,606	29,765	29,519	31,351	30,927	33,369	32,492	34,365	33,585	35,404
(2) Peak Demand (MW)	22,438	24,721	23,408	25,684	24,416	26,981	25,461	28,100	26,459	29,166
(3) Planned Reserve (MW) (1-2)	6,168	5,044	6,111	5,667	6,511	6,388	7,031	6,265	7,126	6,238
(4) Planned Reserve (%) (3÷2) x 100	27.5	20.4	26.1	22.1	26.7	23.7	27.6	22.3	26.9	21.4
(5) Net Transactions 1/ (MW)	250	200	200	0	0	0	0	0	0	0
(6) Total Capability (MW) (1+5)	28,856	29,365	29,719	31,351	30,927	33,369	32,492	34,365	33,585	35,404
(7) Total Reserve (MW) (6-2)	6,418	5,244	6,311	5,667	6,511	6,388	7,031	6,265	7,126	6,238
(8) Total Reserve (%) (7÷2) x 100	28.6	21.2	27.0	22.1	26.7	23.7	27.6	22.3	26.9	21.4
(9) Scheduled Maintenance (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(10) Capability after Maintenance (MW) (6-9)	28,856	29,365	29,719	31,351	30,927	33,369	32,492	34,365	33,585	35,404
(11) Reserve after Maintenance (MW) (10-2)	6,418	5,244	6,311	5,667	6,511	6,388	7,031	6,265	7,126	6,238
(12) Reserve after Maintenance (%) (11÷2) x 100	28.6	21.2	27.0	22.1	26.7	23.7	27.6	22.3	26.9	21.4
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	28,856	29,365	29,719	31,351	30,927	33,369	32,492	34,365	33,585	35,404
(15) Available Reserve (MW) (14-2)	6,418	5,244	6,311	5,667	6,511	6,388	7,031	6,265	7,126	6,238
(16) Available Reserve (%) (15÷2) x 100	28.6	21.2	27.0	22.1	26.7	23.7	27.6	22.3	26.9	21.4
(17) Forced Outages (F.O.) (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(18) Available Capability after F.O. (MW) (14-17)	28,856	29,365	29,719	31,351	30,927	33,369	32,492	34,365	33,585	35,404
(19) Actual Reserve (MW) (18-2)	6,418	5,244	6,311	5,667	6,511	6,388	7,031	6,265	7,126	6,238
(20) Actual Reserve (%) (19÷2) x 100	28.6	21.2	27.0	22.1	26.7	23.7	27.6	22.3	26.9	21.4

1/ Net Transactions = Purchases - Sales

2/ Information on scheduled maintenance and forced outages are not available

Southern SubregionHistorical Perspective

In terms of generating capacity and fuel mix, the Southern Subregion has been in an extremely good position. About 93 percent of this Subregion's electric generation during 1978 came from non-oil sources. A total of 11.5 million barrels of oil were used for electric generation in 1978 and about 36 percent of this was distillate. A total of 33 million Mcf of natural gas and 32 million tons of coal were also burned during that year. The Southern Subregion was a major exporter of coal-by-wire during 1979 to both Middle South Utilities in the Southwest Power Pool and the Florida Subregion in SERC.

Actual mid-period (1978) summer generating capacity by fuel type and resulting 1978 actual energy production is shown on Table 7B.1.

TABLE 7B.1

Actual 1978 Summer Generating Capacity By Fuel TypeSouthern Company Group Region

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>Capacity</u>		<u>Generation</u>	
		<u>MW</u>	<u>% of Total</u>	<u>GWH</u>	<u>% of Total</u>
Steam	Nuclear	1,575	6.4	10,197	10.1
Steam	Coal	16,494	67.2	74,509	73.5
Steam	Oil	1,705	6.9	7,016	6.9
Steam	Gas	413	1.7	2,015	2.0
Hydro	Water	2,982	12.1	6,900	6.8
Pumped Storage	Water	145	0.6	(196)	(0.2)
Gas Turbine	Oil	1,225	5.0	594	0.6
Gas Turbine	Gas	21	0.1	271	0.3
Combined Cycle	Oil	0	0.0	0	0.0
Combined Cycle	Gas	0	0.0	0	0.0
Other		<u>0</u>	<u>0.0</u>	<u>0</u>	<u>0.0</u>
Total		24,560	100.0	101,306	100.0

Load Growth in the Southern Subregion increased at an average annual rate of about 9.0 percent between 1968 and 1972 and at a rate of about 4.5 percent between 1972 and 1977. This has continued to moderate during the last three years as shown on Table 7B.2.

TABLE 7B.2

Actual Annual Net Energy for Load, Summer and Winter Peak Demands
and Load Factor 1/

Southern Company Group Region

<u>Item</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy in GWH	98,185	103,706	104,048
Summer Peak Demand in MW	19,115	20,464	20,372
Winter Peak Demand in MW 2/	16,674	17,368	16,969
Annual Load Factor in %	58.6	57.9	58.3

The average annual growth rate of electric energy use in the Southern Subregion covering 1977 through 1979 was 3.0 percent. The summer peak demand growth rate was 3.3 percent while the winter peak demand has not shown any consistent growth. This slower growth rate will enable the Southern Subregion to maintain their favorable fuel mix position in the future with just incremental generation additions since they are not in an all out fuel conversion situation.

The Southern Subregion attempts to maintain planned generation reserve of between 17 and 20 percent of annual peak demand. Their operating criteria requires that an operating reserve equal to 1.5 times the largest generating unit in service be maintained at all times. At least 50 percent of this amount must be spinning. The largest generating unit in the Southern Subregion is currently about 880 MW. Tables 7B.3 through 7B.5 give the actual reserve situations that occurred in the Southern Subregion for 1977 through 1979 for each of the three summer months (June, July and August) and the three winter months (December, January and February). Planned reserve fell below 17 percent of monthly peak demand during five of the past

1/ Source - Form No. 12E-2.

2/ Winter period for each year includes December of that year plus January and February of the following year.

nine summer peak periods. The lowest planned reserve as a percent of monthly peak was 8.0 percent and occurred in July 1977. The smallest actual reserve percentage was 5.9 percent and occurred in June 1977. Actual reserve exceeded the operating reserve requirement of 1,320 MW during all but one of the peak periods examined.

There were about 11,600 miles of 115 kV and 161 kV, 5,600 miles of 230 kV and 900 miles of 500 kV transmission lines in operation in 1978 with a capability of about 3.6 million MW-miles. This resulted in a transmission to generating capacity ratio of about 150 MW-miles per MW.

The Southern Subregion operates as a single control area or power pool.

Current Perspective

The 1980 summer peak demand for the Southern Subregion is expected to be in the range of 21,341 MW to 21,909 MW. This represents an increase over the 1979 summer peak of between 4.8 and 7.5 percent, respectively. While the lower figure may be more realistic, using the higher number produces a conservative planned generation reserve of over 31 percent for the 1980 summer peak. Two conventional hydroelectric, two pumped storage, one gas turbine and one coal-fired generating units representing a total of 487 MW capacity or 2.2 percent of peak demand are scheduled for service prior to the summer peak.

Planned reserve for the 1980 winter peak is expected to be 59 percent or greater. The Farley No. 2 nuclear generating unit rated at 807 MW or 4.3 percent of the winter peak demand is scheduled for operation in September 1980.

Reserve after maintenance is expected to exceed 5,900 MW for both the 1980 summer and winter peak demand periods, even discounting the planned 1980 generating unit additions. This far exceeds the operating reserve requirement of 1,320 MW. Table 7B.6 gives the current reserve picture for the three summer and three winter months for 1980.

The Southern Subregion has a curtailment program whereby a total of about 3,450 MW of load could be reduced by manual means in the event of an extreme emergency. This represents about 16 percent of their forecast summer peak demand. The amounts and methods of reducing loads are shown on Table 7B.7.

TABLE 7E.7

Emergency Curtailment Program
Southern Company Group Region

<u>Method</u>	<u>Amount in MW</u>
Curtailment of non-essential utility load	75
Interruption of contract interruptible load	211
Voltage reduction <u>1/</u>	0
Voluntary industrial curtailment--6 to 10 hour notice required	90
Rotating distribution feeder outages--3 to 4 hour notice required	45-85
Load shedding by supervisory control	3,000

The non-simultaneous transmission import capability of the Southern Subregion over and above scheduled purchases and sales, is 3,850 MW. This is about 18 percent of the projected summer peak demand.

Future Perspective

The summer peak demand of the Southern Subregion is forecasted to increase at an average annual rate of 4.1 percent between 1980 and 1989; from 21,366 MW to 30,629 MW. This includes a contract interruptible load of 211 MW. The winter peak demand is projected to increase from 18,116 MW in 1980 to 27,122 MW in 1989, an annual growth rate of 4.6 percent. The Southern Subregion is expected to continue to be a summer peaking region during this period even though the winter demand is projected to increase at a slightly greater rate than the summer peak demand. Electric energy use is expected to increase at an average annual rate of 4.1 percent, from 108,168 GWH in 1980 to 155,753 GWH in 1989. Annual load factor is expected to remain relatively constant at about 58 percent between 1980 and 1989. While the Southern Subregion load forecasts appear to be optimistic, their generating capacity addition program could readily be adjusted to a lower growth, if it becomes necessary.

1/ No appreciable reduction in load has been observed in the Southern Subregion during voltage reduction tests of up to 5 percent.

Three nuclear units are scheduled for addition in the Southern Subregion between 1980 and 1989. The remainder of the planned capacity additions for this period are scheduled to be hydro and coal-fired units. Planned unit additions are shown in detail on attached Table 7B.8. Southern estimates that between 16,000 and 24,000 GWP of non-oil/gas electric generation could be available for sale during this period because of their favorable fuel mix position. This will also permit them to retire a number of oil-fired units and improve their peaking economics. The capacity mix is shown on Table 7E.9 for mid-year 1980, 1984 and 1989, respectively.

TABLE 7B.9

Mid-year Generating CapacitySouthern Company Group Region

Unit-Fuel Type	1980		1984		1989	
	MW	% of Total	MW	% of Total	MW	% of Total
ST-Nuc	2,340	8.5	3,184	10.1	5,521	14.6
ST-Coal	18,264	66.6	21,161	67.2	24,325	64.4
ST-Oil	1,705	6.2	1,650	5.2	1,524	4.0
ST-Gas	382	1.4	382	1.2	382	1.0
Hydro	3,095	11.3	3,484	11.1	3,898	10.3
PS	357	1.3	357	1.1	1,032	2.7
GT-Oil	1,268	4.6	1,268	4.0	1,111	3.0
GT-Gas	30	0.1	30	0.1	0	0.0
CC-Oil	0	0.0	0	0.0	0	0.0
CC-Gas	0	0.0	0	0.0	0	0.0
Other	0	0.0	0	0.0	0	0.0
Total	27,441	100.0	31,516	100.0	37,793	100.0

Electric region's ten-year baseline projections of generating capacity, seasonal peak demands and reserve margins are shown on attached Table 7B.10. Total reserve, shown on Table 7B.10 in percent of peak demand, are expected to be more than adequate in the Southern Subregion during the 1981 through 1989 period. Total reserve is expected to exceed 23 percent of peak demand during each of the next eighteen peak load seasons. The largest generating unit liabilities during this period will be the Vogtle No. 1 and No. 2 nuclear generating units rated at 1,150 MW each. These units are scheduled for service in November of 1984 and 1987, respectively. The addition of these units will increase the operating reserve requirement from 1,320 MW to 1,725 MW, effective in November 1984. Reserve after maintenance is expected to exceed 6,000 MW during the 1981 through 1984 period.

Possibly the only bulk power supply weakness of the region is in the transmission system in lower Alabama. Concomitant with the installation of the second generating unit in 1981 at the Daniel Plant near Mobile, Alabama, power flows are expected to be altered to where the Logtown-Slidell 230 kV tie between SWPP and SERC will load up before the 500 kV lines between these respective council areas. A 500 kV line interconnecting the existing 500 kV system at New Orleans in SWPP with the existing 500 kV system near Montgomery, Alabama in SERC via Mobile appears to be necessary in order to relieve this bottleneck.

Planned transmission line additions during 1980 - 1989 period consist of 750 miles of 500 kV, 1,100 miles of 230 kV and 100 miles of 115 kV lines representing a combined transmission capacity of about 1.2 million MW-miles. Generating capacity additions during this period amount to about 10,800 MW, resulting in a transmission to generating capacity additions ratio of about 110 MW-miles per MW.

Table 7B.3

HISTORICAL CAPABILITY AND RESERVE MARGINS
SOUTHERN COMPANY GROUP REGION

	1977 Summer			1977/1978 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	20,637	20,637	20,637	21,909	21,773	21,786
(2) Peak Demand (MW)	13,525	19,115	18,575	15,258	16,674	16,643
(3) Planned Reserve (MW) (1-2)	2,112	1,522	2,062	6,651	5,099	5,143
(4) Planned Reserve (%) $(3 \div 2) \times 100$	11.4	8.0	11.1	43.6	30.6	30.9
(5) Net Transactions $1/$ (MW)	3,821	3,155	3,098	3,129	1,353	2,410
(6) Total Capability (MW) (1+5)	24,458	23,792	23,735	25,038	23,126	24,196
(7) Total Reserve (MW) (6-2)	5,933	4,677	5,160	9,780	6,452	7,553
(8) Total Reserve (%) $(7 \div 2) \times 100$	32.0	24.5	27.8	64.1	38.7	45.4
(9) Scheduled Maintenance (MW)	451	18	17	3,400	2,224	1,666
(10) Capability After Maintenance (MW) (6-9)	24,007	23,774	23,718	21,638	20,902	22,530
(11) Reserve After Maintenance (MW) (10-2)	5,482	4,659	5,143	6,380	4,228	5,887
(12) Reserve After Maintenance (%) $(11 \div 2) \times 100$	29.6	24.4	27.7	41.8	25.4	35.4
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	24,007	23,774	23,718	21,638	20,902	22,530
(15) Available Reserve (MW) (14-2)	5,482	4,659	5,143	6,380	4,228	5,887
(16) Available Reserve (%) $(15 \div 2) \times 100$	29.6	24.4	27.7	41.8	25.4	35.4
(17) Forced Outages (F.O.) (MW)	4,399	2,739	3,144	4,752	2,078	3,429
(18) Available Capability After F.O. (MW) (14-17)	19,608	21,035	20,574	16,886	18,824	19,101
(19) Actual Reserve (MW) (18-2)	1,083	1,920	1,999	1,628	2,150	2,458
(20) Actual Reserve (%) $(19 \div 2) \times 100$	5.9	10.0	10.8	10.7	12.9	14.8

1/ Net Transactions = Purchases - Sales

Table 7B.4

HISTORICAL CAPABILITY AND RESERVE MARGINS
SOUTHERN COMPANY GROUP REGION

	1978 Summer			1978/1979 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	23,097	23,083	23,061	23,929	23,518	23,677
(2) Peak Demand (MW)	20,464	19,332	19,603	15,642	17,368	17,004
(3) Planned Reserve (MW) (1-2)	2,633	3,751	3,458	8,287	6,150	6,673
(4) Planned Reserve (%) (3÷2) x 100	12.9	19.4	17.6	53.0	35.4	39.2
(5) Net Transactions ^{1/} (MW)	2,624	2,171	4,700	2,401	2,529	2,185
(6) Total Capability (MW) (1+5)	25,721	25,254	27,761	26,330	26,047	25,862
(7) Total Reserve (MW) (6-2)	5,257	5,922	8,158	10,688	8,679	8,858
(8) Total Reserve (%) (7÷2) x 100	25.7	30.6	41.6	68.3	50.0	52.1
(9) Scheduled Maintenance (MW)	59	59	6	3,590	1,670	2,490
(10) Capability After Maintenance (MW) (6-9)	25,662	25,195	27,755	22,740	24,377	23,372
(11) Reserve After Maintenance (MW) (10-2)	5,198	5,863	8,152	7,098	7,009	6,368
(12) Reserve After Maintenance (%) (11÷2) x 100	25.4	30.3	41.6	45.4	40.4	37.5
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	25,662	25,195	27,755	22,740	24,377	23,372
(15) Available Reserve (MW) (14-2)	5,198	5,863	8,152	7,098	7,009	6,368
(16) Available Reserve (%) (15÷2) x 100	25.4	30.3	41.6	45.4	40.4	37.5
(17) Forced Outages (F.O.) (MW)	3,861	3,286	5,116	1,875	4,323	3,964
(18) Available Capability After F.O. (MW) (14-17)	21,801	21,909	22,639	20,865	20,054	19,408
(19) Actual Reserve (MW) (18-2)	1,337	2,577	3,036	5,223	2,686	2,404
(20) Actual Reserve (%) (19÷2) x 100	6.5	13.3	15.5	33.4	15.5	14.1

^{1/} Net Transactions = Purchases - Sales

Table 7B.5

HISTORICAL CAPABILITY AND RESERVE MARGINS
SOUTHERN COMPANY GROUP REGION

	1979 Summer			1979/1980 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	23,557	23,543	23,566	24,357	24,540	24,753
(2) Peak Demand (MW)	19,111	19,831	20,372	16,330	16,634	16,969
(3) Planned Reserve (MW) (1-2)	4,446	3,712	3,194	8,027	7,906	7,784
(4) Planned Reserve (%) $(3 \div 2) \times 100$	23.3	18.7	15.7	49.2	47.5	45.9
(5) Net Transactions 1/ (MW)	2,392	1,788	3,227	890	535	1,027
(6) Total Capability (MW) (1+5)	25,949	25,331	26,793	25,247	25,075	25,780
(7) Total Reserve (MW) (6-2)	6,838	5,500	6,421	8,917	8,441	8,811
(8) Total Reserve (%) $(7 \div 2) \times 100$	35.8	27.7	31.5	54.6	50.7	51.9
(9) Scheduled Maintenance (MW)	1,840	1,645	1,657	3,108	2,651	3,329
(10) Capability After Maintenance (MW) (6-9)	24,109	23,686	25,136	22,139	22,424	22,451
(11) Reserve After Maintenance (MW) (10-2)	4,998	3,855	4,764	5,809	5,790	5,482
(12) Reserve After Maintenance (%) $(11 \div 2) \times 100$	26.2	19.4	23.4	35.6	34.8	32.3
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	24,109	23,686	25,136	22,139	22,424	22,451
(15) Available Reserve (MW) (14-2)	4,998	3,855	4,764	5,809	5,790	5,482
(16) Available Reserve (%) $(15 \div 2) \times 100$	26.2	19.4	23.4	35.6	34.8	32.3
(17) Forced Outages (F.O.) (MW)	2,559	2,030	2,960	2,773	697	1,287
(18) Available Capability After F.O. (MW) (14-17)	21,550	21,656	22,176	19,366	21,727	21,164
(19) Actual Reserve (MW) (18-2)	2,439	1,825	1,804	3,036	5,093	4,195
(20) Actual Reserve (%) $(19 \div 2) \times 100$	12.8	9.2	8.9	18.6	30.6	24.7

1/ Net Transactions = Purchases - Sales

Table 7B.6

CURRENT CAPABILITY AND RESERVE MARGINS
SOUTHERN COMPANY GROUP REGION

	1980 Summer			1980/1981 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	28,793	28,834	28,812	29,789	29,807	29,822
(2) Peak Demand (MW)	20,260	21,366	21,909	17,785	18,742	18,182
(3) Planned Reserve (MW) (1-2)	8,533	7,468	6,903	12,004	11,065	11,640
(4) Planned Reserve (%) (3÷2) x 100	42.1	35.0	31.5	67.5	59.0	64.0
(5) Net Transactions 1/ (MW)	(487) 3/	(487) 3/	(487) 3/	(779) 3/	(779) 3/	(779) 3/
(6) Total Capability (MW) (1+5)	28,306	28,347	28,325	29,010	29,028	29,043
(7) Total Reserve (MW) (6-2)	8,046	6,981	6,416	11,225	10,286	10,861
(8) Total Reserve (%) (7÷2) x 100	39.7	32.7	29.3	63.1	54.9	59.7
(9) Scheduled Maintenance (MW)	10	0	0	2,025	1,611	1,801
(10) Capability After Maintenance (MW) (6-9)	28,296	28,347	28,325	26,985	27,417	27,242
(11) Reserve After Maintenance (MW) (10-2)	8,036	6,981	6,416	9,200	8,675	9,060
(12) Reserve After Maintenance (%) (11÷2) x 100	39.7	32.7	29.3	51.7	46.3	49.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	28,296	28,347	28,325	26,985	27,417	27,242
(15) Available Reserve (MW) (14-2)	8,036	6,981	6,416	9,200	8,675	9,060
(16) Available Reserve (%) (15÷2) x 100	39.7	32.7	29.3	51.7	46.3	49.8
(17) Forced Outages (F.O.) (MW) 2/	3,344	3,344	3,344	2,798	2,798	2,798
(18) Available Capability After F.O. (MW) (14-17)	24,952	25,003	24,981	24,187	24,619	24,444
(19) Actual Reserve (MW) (18-2)	4,692	3,637	3,072	6,402	5,877	6,262
(20) Actual Reserve (%) (19÷2) x 100	23.2	17.0	14.0	36.0	31.4	34.4

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the ERA Field Office Staff

3/ () denotes negative number

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TABLE 7B.8

Major Future Generating Unit In-Service Dates
Southern Company Group Region

<u>Unit Designation</u>	<u>Capacity in MW</u>	<u>Fuel Type</u>	<u>In-Service Date</u>		<u>Change in MW-months</u>
			<u>As of 4/79</u>	<u>As of 4/80</u>	
Tombigbee No. 3	225	Coal	6/79	4/80	2,250
Farley No. 2	807	Nuc.	4/81	9/80	(5,649)
Daniel No. 2	503	Coal	6/81	6/81	0
Scherer No. 1	808	Coal	2/82	2/82	0
Miller No. 2	654	Coal	6/82	6/83	7,848
Scherer No. 2	808	Coal	2/84	2/84	0
Vogtle No. 1	1,150	Nuc.	11/84	11/84	0
Miller No. 3	654	Coal	6/83	6/85	15,696
Scherer No. 3	808	Coal	2/85	2/87	19,392
Effingham No. 2	163	Coal	3/86	3/87	1,956
Rocky Mountain	675	Hydro	6/84	4/87	22,950
Miller No. 4	654	Coal	6/84	6/87	23,544
Vogtle No. 2	1,150	Nuc.	11/87	11/87	0
Scherer No. 4	808	Coal	2/87	2/89	19,392
Site A-1	783	Coal	6/87	6/90	28,188
Site A-2	783	Coal	6/88	6/91	28,188

Table 7B.10

FUTURE CAPABILITY AND RESERVE MARGINS 1981-1989
SOUTHERN COMPANY GROUP REGION

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	29,144	29,156	29,952	29,964	30,723	30,720	31,516	32,790
(2) Peak Demand (MW)	22,145	18,992	22,985	19,356	24,207	20,924	25,385	21,754
(3) Planned Reserve (MW) (1-2)	6,999	10,164	6,967	10,608	6,516	9,796	6,131	11,036
(4) Planned Reserve (%) (3÷2) x 100	31.6	53.5	30.3	50.2	26.9	45.8	24.2	50.7
(5) Net Transactions 1/ (MW)	(110) 3/	(390) 3/	(110) 3/	(390) 3/	(110) 3/	(390) 3/	(110) 3/	(390) 3/
(6) Total Capability (MW) (1+5)	29,034	28,766	29,842	29,574	30,613	30,330	31,406	32,400
(7) Total Reserve (MW) (6-2)	6,889	9,774	6,857	9,518	6,406	9,405	6,021	10,646
(8) Total Reserve (%) (7÷2) x 100	31.1	51.5	29.8	48.2	26.5	45.0	23.7	48.9
(9) Scheduled Maintenance (MW)	0	2,159	0	2,666	0	2,935	0	3,546
(10) Capability After Maintenance (MW) (6-9)	29,034	26,607	29,842	26,908	30,613	27,395	31,406	28,854
(11) Reserve After Maintenance (MW) (10-2)	6,889	7,615	6,857	6,952	6,406	6,471	6,021	7,100
(12) Reserve After Maintenance (%) (11÷2) x 100	31.1	40.1	29.8	34.8	26.5	30.9	23.7	32.6
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	29,034	26,607	29,842	26,908	30,613	27,395	31,406	28,854
(15) Available Reserve (MW) (14-2)	6,889	7,615	6,857	6,952	6,406	6,471	6,021	7,100
(16) Available Reserve (%) (15÷2) x 100	31.1	40.1	29.8	34.8	26.5	30.9	23.7	32.6
(17) Forced Outages (F.O.) (MW) 2/	3,344	2,798	3,344	2,798	3,344	2,798	3,444	2,798
(18) Available Capability After F.O. (MW) (14-17)	25,690	23,809	26,498	24,110	27,269	24,597	27,962	26,056
(19) Actual Reserve (MW) (18-2)	3,545	4,817	3,513	4,154	3,062	3,673	2,577	4,302
(20) Actual Reserve (%) (19÷2) x 100	16.0	25.4	15.3	20.8	12.6	17.6	10.2	19.8

XI.7.32

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the ERA Field Office Staff

3/ () denotes negative number

Table 7B.10

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FUTURE CAPABILITY AND RESERVE MARGINS
SOUTHERN COMPANY GROUP REGION

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	33,571	33,540	33,948	33,793	36,059	35,947	37,045	36,908	37,793	37,734
(2) Peak Demand (MW)	26,348	22,728	27,291	23,825	28,540	24,909	29,656	25,966	30,629	27,122
(3) Planned Reserve (MW) (1-2)	7,223	10,812	6,657	9,968	7,519	11,038	7,389	10,942	7,164	10,612
(4) Planned Reserve (%) (3÷2) x 100	27.4	47.6	24.4	41.8	26.3	44.3	24.9	42.1	23.4	39.1
(5) Net Transactions 1/ (MW)	(110)	(340)	(60)	(140)	140	(140)	140	(140)	140	(140)
(6) Total Capability (MW) (1+5)	33,461	33,200	33,888	33,653	36,199	35,807	37,185	36,768	37,933	37,594
(7) Total Reserve (MW) (6-2)	7,113	10,472	6,597	9,828	7,659	10,898	7,529	10,802	7,304	10,472
(8) Total Reserve (%) (7÷2) x 100	27.0	46.1	24.2	41.3	26.8	43.8	25.4	41.6	23.8	38.6
(9) Scheduled Maintenance (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(10) Capability after Maintenance (MW) (6-9)	33,461	33,200	33,888	33,653	36,199	35,807	37,185	36,768	37,933	37,594
(11) Reserve after Maintenance (MW) (10-2)	7,113	10,472	6,597	9,828	7,659	10,898	7,529	10,802	7,304	10,472
(12) Reserve after Maintenance (%) (11÷2) x 100	27.0	46.1	24.2	41.3	26.8	43.8	25.4	41.6	23.8	38.6
(13) Inoperable Capability (MW)	0	5	0	5	0	5	0	5	0	5
(14) Available Capability (MW) (10-13)	33,461	33,195	33,888	33,648	36,199	35,802	37,185	36,763	37,933	37,589
(15) Available Reserve (MW) (14-2)	7,113	10,467	6,597	9,823	7,659	10,893	7,529	10,797	7,304	10,467
(16) Available Reserve (%) (15÷2) x 100	27.0	46.1	24.2	41.2	26.8	43.7	25.4	41.6	23.8	38.6
(17) Forced Outages (F.O.) (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(18) Available Capability after F.O. (MW) (14-17)	33,461	33,195	33,888	33,648	36,199	35,802	37,185	36,763	37,933	37,589
(19) Actual Reserve (MW) (18-2)	7,113	10,467	6,597	9,823	7,659	10,893	7,529	10,797	7,304	10,467
(20) Actual Reserve (%) (19÷2) x 100	27.0	46.1	24.2	41.2	26.8	43.7	25.4	41.6	23.8	38.6

1/ Net Transactions = Purchases - Sales

2/ Information on scheduled maintenance and forced outages are not available

() denotes negative number

TVA SubregionHistorical Perspective

Load growth over the past three years has been somewhat of an anomaly in the TVA Subregion. Electric energy use has increased at an average annual rate of 3.7 percent while both the summer and winter peak demands have decreased. Details are shown on Table 7C.1.

Table 7C.1

Actual Annual Net Energy for Load, Summer and Winter Peak Demands
and Load Factors

Tennessee Valley Authority Group Region 1/

<u>Item</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy in GWh	114,978	122,793	123,456
Summer Peak Demand in MW	18,953	18,740	18,795
Winter Peak Demand in MW	21,992	21,540	20,745
Annual Load Factor in %	59.7	65.0	67.9

The TVA Subregion is a relatively high load factor system. This, coupled with the number of large sized units in the subregion generally requires that generation reserves of between 25 and 30 percent be installed for this area. The exact reserve criteria is determined by loss-of-load probability mathematics. Reserves are planned to meet a risk index of one day in ten years. The TVA Subregion maintains operating reserves equal to the largest generating unit in service plus a 200 MW margin for scheduling error and regulation. One-half of the operating reserve is to be spinning at all time and the other one-half is to be available within ten minutes. The largest generating unit in the TVA Subregion is rated at 1,275 MW. Tables 7C.2 through 7C.4 give the actual reserve situations that occurred in the TVA Subregion for 1977 through 1979 for each of the three summer months (June, July and August) and the three winter months (December, January and February). There were five peak periods when planned reserves fell below 25 percent of monthly peak. The lowest planned reserve was 15.8 percent and occurred during January 1978. Actual reserve

1/ Source - Form No. 12E-2

did not meet the operating reserve requirement during eight of the eighteen historical peak periods. The lowest actual reserve level was 0.3 percent of peak demand and occurred in January 1978.

Generating capacity (summer rating) by fuel type for 1978 and resulting energy production is shown on Table 7C.5

A total of 6.8 million barrels of oil was burned in the TVA Subregion during 1978 to produce electricity, all of which was distillate. No natural gas was used but about 35.9 million tons of coal was consumed in electric production during 1978. There were three nuclear generating units in service in the TVA Subregion between 1977 and 1979.

The TVA Subregion had about 9,000 miles of 161 kV, about 1,800 miles of 500 kV and about 200 miles of other miscellaneous transmission lines at or above 115 kV at the end of 1979. This is a transmission capability of about 3.1 million MW-miles which translates to a transmission to generating capacity ratio of about 110 MW-miles per MW.

TVA has a seasonal diversity interchange agreement with numerous Southwest Power Pool (SWPP) companies where TVA exports power in the summer and imports power during the winter. The original agreement was signed in 1962 for interchange of 1,500 MW. This was changed to 1,100 MW during 1979 and will be reduced again to 700 MW during 1980. The 1980 schedule is to be followed for the next ten years. The original diversity agreement justified the installation of about 940 miles of 500 kV and 220 miles of 345 kV lines between TVA and SWPP and is a major reason for the high interconnection capacity (4,500 MW) between SERC and SWPP.

Forced outages of generating equipment on the TVA system currently exceed scheduled maintenance outage hours by about three times. Boiler tube failures have been a major cause of generating unit forced outages. During 1977 TVA undertook an intense program to improve the productivity of its generating units. The success of this program is important to the future generation reliability of the TVA Subregion.

The TVA Subregion operates as a single control area or power pool.

Current Perspective

The 1980 summer peak demand of the TVA Subregion is expected to be in the range of 20,188 MW to 20,370 MW. The 1980 winter peak demand is expected to be in the range of 22,290 MW to 23,543 MW. Table 7C.6 gives the current reserve picture for three summer and three winter months for 1980.

Actual reserve for the summer peak period are not expected to meet

the operating reserve requirement for the region and may not be adequate to replenish the loss of the largest generating unit. This does not include any contribution from the Sequoyah No. 1 nuclear unit rated at 1,148 MW. A temporary license for this unit was issued on February 29, 1980 to permit testing at power levels not exceeding 5 percent. It is doubtful that this unit can be commercially available for this summer but some increased output from this unit appears possible. Some relief is possible from hydro capacity since reservoir storages are full and no adverse hydrologic condition is expected. Also, the summer peak forecast represents an 8.4 percent increase over the 1979 actual summer peak demand and there is a possibility that this may not materialize.

A great strength of the TVA Subregion is the import capability of the transmission system. Non-simultaneous import capability, over and above scheduled interchange, is 6,150 MW for the 1980 summer peak period. TVA has a load relief program whereby 2,043 MW of load could be reduced in an emergency. This is about 10 percent of the estimated 1980 summer peak demand. The amounts and methods of reducing load are shown in Table 7C.7.

Table 7C.7

Emergency Curtailment Program
Tennessee Valley Authority Group Region

<u>Method</u>	<u>Amount in MW</u>
Curtailment of non-essential utility load	35
Interruption of contract interruptible load	888
Voltage reduction (5%)	120
Public appeal	1,000

Operating reserve for the 1980 winter peak period should be adequate particularly if the Sequoyah No. 1 nuclear unit becomes fully licensed by this time.

Future Perspective

The TVA Subregion is forecasting their annual electric energy use to increase from 130,150 GWh in 1980 to 182,927 GWh in 1989. This is an average annual growth rate of about 3.9 percent which is comparable to their electric energy growth rate during the past three years. Their summer peak demand is estimated to grow at an average annual

rate of 3.8 percent, from 20,188 MW in 1980 to 28,292 in 1989. Their winter peak demand is expected to increase from 23,543 MW in 1980 to 31,752 MW in 1989, an average annual growth rate of 3.4 percent. Although TVA is expected to remain a winter peaking area, the summer peak is forecasted to increase at a slightly greater rate than the winter. Annual load factor is expected to increase slightly from 63.1 percent in 1980 to 65.8 percent in 1989.

All of TVA's future generating units are scheduled to be nuclear. These are shown on attached Table 7C.8. A total of 13 nuclear units are planned for operation between 1980 and 1989. Since TVA does not use oil except for peaking purposes, additional nuclear generation will not substantially reduce oil use but will greatly reduce dependence on coal and improve the flexibility of their fuel supply over the long term. The capacity mix as currently planned is shown on Table 7C.9 for mid-year 1980, 1984 and 1989, respectively.

Electric region's ten-year baseline projections of generating capacity, peak demand and reserve margins are shown on attached Table 7C.10. As shown on this Table total reserve are 29 percent or higher in every year between 1981 and 1989.

During the past year nuclear units in the TVA Subregion have been delayed a total of 505,128 MW-months. This is almost three times the region's current annual electric energy use. Assuming a one-year delay in the present planned installation dates to allow for unforeseen construction, certification and licensing developments would still allow TVA to maintain planned reserve of at least 25 percent for all but essentially three peak seasons. A two-year delay after 1984 would lower the planned reserve below 25 percent for six of ten peak periods between 1985 and 1989, however, planned reserve below 20 percent is not expected. Possibly the most critical period is the winter of 1981 where planned reserve would drop to 19.7 percent if the Sequoyah No. 2 and Watts Bar No. 1 nuclear generating units are not installed as presently planned. These units are currently scheduled for operation in June 1981 and September 1981, respectively. Their total combined capability is 2,325 MW.

The largest generating unit to be added during the period is rated at 1,285 MW which is comparable to the existing largest size unit on the system.

A total of 1,060 miles of 500 kV lines with a transmission capacity of about 1.3 million MW miles are planned for addition between 1980 and 1989. The net generating capacity additions during this period are about 15,800 MW.

TABLE 7C.2

HISTORICAL CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1977 Summer			1977/1978 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	25,155	25,180	25,128	25,383	25,456	25,473
(2) Peak Demand (MW)	18,345	18,953	18,833	20,733	21,992	20,844
(3) Planned Reserve (MW) (1-2)	6,810	6,227	6,295	4,650	3,464	4,629
(4) Planned Reserve (%) (3÷2) x 100	37.1	32.9	33.4	22.4	15.8	22.2
(5) Net Transactions 1/ (MW)	(243) 2/	10	(1,969) 2/	4,184	2,536	3,274
(6) Total Capability (MW) (1+5)	24,912	25,190	23,159	29,567	27,992	28,747
(7) Total Reserve (MW) (6-2)	6,567	6,237	4,326	8,834	6,000	7,903
(8) Total Reserve (%) (7÷2) x 100	35.8	32.9	23.0	42.6	27.3	37.9
(9) Scheduled Maintenance (MW)	1,142	341	551	1,622	487	1,280
(10) Capability after Maintenance (MW) (6-9)	23,770	24,849	22,608	27,945	27,505	27,467
(11) Reserve after Maintenance (MW) (10-2)	5,425	5,896	3,775	7,212	5,513	6,623
(12) Reserve after Maintenance (%) (11÷2) x 100	29.6	31.1	20.0	34.8	25.1	31.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	23,770	24,849	22,608	27,945	27,505	27,467
(15) Available Reserve (MW) (14-2)	5,425	5,896	3,775	7,212	5,513	6,623
(16) Available Reserve (%) (15÷2) x 100	29.6	31.1	20.0	34.8	25.1	31.8
(17) Forced Outages (F.O.) (MW)	3,584	4,921	2,157	7,114	5,450	5,861
(18) Available Capability after F.O. (MW) (14-17)	20,186	19,928	20,451	20,831	22,055	21,606
(19) Actual Reserve (MW) (18-2)	1,841	975	1,618	98	63	762
(20) Actual Reserve (%) (19÷2) x 100	10.0	5.1	8.6	0.5	0.3	3.7

1/ Net Transactions = Purchases - Sales

2/ () denotes negative number

Table 7C.3

HISTORICAL CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1978 Summer			1978/1979 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	25,397	25,336	25,309	25,354	25,639	26,106
(2) Peak Demand (MW)	18,600	18,155	18,282	18,928	21,540	21,179
(3) Planned Reserve (MW) (1-2)	6,797	7,181	7,027	6,426	4,099	4,927
(4) Planned Reserve (%) $(3 \div 2) \times 100$	36.5	39.6	38.4	33.9	19.0	23.3
(5) Net Transactions $\frac{1}{2}$ (MW)	(1,064) $\frac{2}{2}$	(244) $\frac{2}{2}$	(710) $\frac{2}{2}$	2,292	2,578	1,552
(6) Total Capability (MW) (1+5)	24,333	25,092	24,599	27,646	28,217	27,658
(7) Total Reserve (MW) (6-2)	5,733	6,937	6,317	8,718	6,677	6,479
(8) Total Reserve (%) $(7 \div 2) \times 100$	30.8	38.2	34.6	46.1	31.0	30.6
(9) Scheduled Maintenance (MW)	362	729	629	3,063	2,255	371
(10) Capability after Maintenance (MW) (6-9)	23,971	24,363	23,970	24,583	25,962	27,287
(11) Reserve after Maintenance (MW) (10-2)	5,371	6,208	5,688	5,655	4,422	6,108
(12) Reserve after Maintenance (%) $(11 \div 2) \times 100$	28.9	34.2	31.1	29.9	20.5	28.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	23,971	24,363	23,970	24,583	25,962	27,287
(15) Available Reserve (MW) (14-2)	5,371	6,208	5,688	5,655	4,422	6,108
(16) Available Reserve (%) $(15 \div 2) \times 100$	28.9	34.2	31.1	29.9	20.5	28.8
(17) Forced Outages (F.O.) (MW)	4,707	4,281	4,614	4,190	4,103	4,354
(18) Available Capability after F.O. (MW) (14-17)	19,264	20,082	19,356	20,393	21,859	22,933
(19) Actual Reserve (MW) (18-2)	664	1,927	1,074	1,465	319	1,754
(20) Actual Reserve (%) $(19 \div 2) \times 100$	3.6	10.6	5.9	7.7	1.5	8.3

$\frac{1}{2}$ Net Transactions = Purchases - Sales

$\frac{2}{2}$ () denotes negative number

Table 7C.4

HISTORICAL CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1979 Summer			1979/1980 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	26,437	26,347	26,330	26,865	26,951	26,946
(2) Peak Demand (MW)	17,975	18,270	18,795	19,529	20,387	20,745
(3) Planned Reserve (MW) (1-2)	8,462	8,077	7,535	7,336	6,564	6,201
(4) Planned Reserve (%) (3÷2) x 100	47.1	44.2	40.1	37.6	32.2	29.9
(5) Net Transactions ^{1/} (MW)	(682) ^{2/}	(1,249) ^{2/}	(1,784) ^{2/}	1,375	(158) ^{2/}	798
(6) Total Capability (MW) (1+5)	25,755	25,098	24,546	28,240	26,793	27,744
(7) Total Reserve (MW) (6-2)	7,780	6,828	5,751	8,711	6,406	6,999
(8) Total Reserve (%) (7÷2) x 100	43.3	37.4	30.6	44.6	31.4	33.7
(9) Scheduled Maintenance (MW)	3,633	657	448	579	1,540	1,540
(10) Capability after Maintenance (MW) (6-9)	22,122	24,441	24,098	27,661	25,253	26,204
(11) Reserve after Maintenance (MW) (10-2)	4,147	6,171	5,303	8,132	4,866	5,459
(12) Reserve after Maintenance (%) (11÷2) x 100	23.1	33.8	28.2	41.6	23.9	26.3
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	22,122	24,441	24,098	27,661	25,253	26,204
(15) Available Reserve (MW) (14-2)	4,147	6,171	5,303	8,132	4,866	5,459
(16) Available Reserve (%) (15÷2) x 100	23.1	33.8	28.2	41.6	23.9	26.3
(17) Forced Outages (F.O.) (MW)	799	4,163	4,604	4,521	1,732	2,962
(18) Available Capability after F.O. (MW) (14-17)	21,323	20,278	19,494	23,140	23,521	23,242
(19) Actual Reserve (MW) (18-2)	3,348	2,008	699	3,611	3,134	2,497
(20) Actual Reserve (%) (19÷2) x 100	18.6	11.0	3.7	18.5	15.4	12.0

^{1/} Net Transactions = Purchases - Sales

^{2/} () denotes negative number

Table 7C.5

Actual 1978 Summer Generating Capacity by Fuel TypeTennessee Valley Authority Group Region

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>MW</u>	<u>% of Total</u>	<u>GWh</u>	<u>% of Total</u>
Steam	Nuclear	3,201	12.3	16,911	14.7
Steam	Coal	16,249	62.5	78,469	68.1
Steam	Oil	0	0.0	0	0.0
Steam	Gas	0	0.0	0	0.0
Hydro	Water	4,306	16.6	17,023	14.8
Pumped Storage	Water	0	0.0	(25)	0.0
Gas Turbine	Oil	2,224	8.6	2,838	2.4
Gas Turbine	Gas	0	0.0	0	0.0
Combined Cycle	Oil	0	0.0	0	0.0
Combined Cycle	Gas	0	0.0	0	0.0
Other		0	0.0	0	0.0
Total		25,980	100.0	115,216	100.0

TABLE 7C.6

CURRENT CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1980 Summer			1980/1981 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	27,454	27,434	27,424	28,838	28,808	28,878
(2) Peak Demand (MW)	19,350	20,370	20,370	20,890	22,290	21,790
(3) Planned Reserve (MW) (1-2)	8,104	7,064	7,054	7,948	6,518	7,088
(4) Planned Reserve (%) (3÷2) x 100	41.9	34.7	34.6	38.0	29.2	32.5
(5) Net Transactions ^{1/} (MW)	(1,580) ^{3/}	(1,580) ^{3/}	(1,580) ^{3/}	1,100	1,100	1,100
(6) Total Capability (MW) (1+5)	25,874	25,854	25,844	29,938	29,908	29,978
(7) Total Reserve (MW) (6-2)	6,524	5,484	5,474	9,048	7,618	8,188
(8) Total Reserve (%) (7÷2) x 100	33.7	26.9	26.9	43.3	34.2	37.6
(9) Scheduled Maintenance (MW)	665	704	704	2,597	747	1,087
(10) Capability after Maintenance (MW) (6-9)	25,209	25,150	25,140	27,341	29,161	28,891
(11) Reserves after Maintenance (MW) (10-2)	5,859	4,780	4,770	6,451	6,871	7,101
(12) Reserves after Maintenance (%) (11÷2) x 100	30.3	23.5	23.4	30.9	30.8	32.6
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	25,209	25,150	25,140	27,341	29,161	28,891
(15) Available Reserve (MW) (14-2)	5,859	4,780	4,770	6,451	6,871	7,101
(16) Available Reserve (%) (15÷2) x 100	30.3	23.5	23.4	30.9	30.8	32.6
(17) Forced Outages (F.O.) (MW) ^{2/}	3,663	3,663	3,663	3,680	3,974	3,908
(18) Available Capability after F.O. (MW) (14-17)	21,546	21,487	21,477	23,661	25,187	24,983
(19) Actual Reserve (MW) (18-2)	2,196	1,117	1,107	2,771	2,897	3,193
(20) Actual Reserve (%) (19÷2) x 100	11.3	5.5	5.4	13.3	13.0	14.7

- ^{1/} Net Transactions = Purchases - Sales
^{2/} Estimated by TVA
^{3/} () denotes negative number

Table 7C.8

Major Future Generating Unit In-Service Dates
Tennessee Valley Authority Group Region

<u>Unit Designation</u>	<u>Capacity in MW</u>	<u>Fuel Type</u>	<u>In-Service Date</u>		<u>Change in MW-months</u>
			<u>As Of 4/79</u>	<u>As Of 4/80</u>	
Sequoyah No. 1	1,148	Nuc.	10/79	6/80	9,184
Sequoyah No. 2	1,148	Nuc.	6/80	6/81	13,776
Watts Bar No. 1	1,177	Nuc.	6/80	9/81	17,655
Watts Bar No. 2	1,177	Nuc.	3/81	6/82	17,655
Bellefonte No. 1	1,213	Nuc.	9/81	9/83	29,112
Bellefonte No. 2	1,213	Nuc.	6/82	6/84	29,112
Yellow Creek No. 1	1,285	Nuc.	5/85	11/85	7,710
Hartsville No. 1	1,233	Nuc.	6/83	7/86	45,621
Phipps Bend No. 1	1,233	Nuc.	8/84	3/87	38,223
Hartsville No. 2	1,233	Nuc.	6/84	7/87	45,621
Yellow Creek No. 2	1,285	Nuc.	5/86	4/88	29,555
Hartsville No. 3	1,233	Nuc.	12/83	6/89	81,378
Phipps Bend No. 2	1,233	Nuc.	8/85	8/89	59,184
Hartsville No. 4	1,233	Nuc.	12/84	6/90	81,378

Table 7C.9

Mid-year Generating Capacity
Tennessee Valley Authority Group Region

Unit Fuel Type	1980		1984		1989	
	in MW	% of Total	in MW	% of Total	in MW	% of Total
ST-Nuc	4,349	15.3	10,277	29.9	17,779	42.5
ST-Coal	16,249	57.2	16,249	47.3	16,249	38.8
ST-Oil	0	0.0	0	0.0	0	0.0
ST-Gas	0	0.0	0	0.0	0	0.0
Hydro	4,306	15.1	4,306	12.5	4,306	10.3
PS	1,300	4.6	1,300	3.8	1,300	3.1
GT-Oil	2,224	7.8	2,224	6.5	2,224	5.3
GT-Gas	0	0.0	0	0.0	0	0.0
CC-oil	0	0.0	0	0.0	0	0.0
CC-Gas	0	0.0	0	0.0	0	0.0
Other	0	0.0	0	0.0	0	0.0
Total	28,428	100.0	34,356	100.0	41,858	100.0

Table 7C.10

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FUTURE CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	29,576	30,872	31,930	32,049	31,930	33,262	34,356	34,475
(2) Peak Demand (MW)	21,108	24,779	22,572	25,410	23,129	26,496	24,833	27,996
(3) Planned Reserve (MW) (1-2)	8,468	6,093	9,358	6,639	8,801	6,766	9,523	6,479
(4) Planned Reserve (%) (3÷2) x 100	40.1	24.6	41.5	26.1	38.1	25.5	38.3	23.1
(5) Net Transactions 1/ (MW)	(1,100) 3/	1,100	(1,100) 3/	1,100	(1,100) 3/	1,100	(1,100) 3/	1,100
(6) Total Capability (MW) (1+5)	28,476	31,972	30,830	33,149	30,830	34,362	33,256	35,575
(7) Total Reserve (MW) (6-2)	7,368	7,193	8,258	7,739	7,701	7,866	8,423	7,579
(8) Total Reserve (%) (7÷2) x 100	34.9	29.0	36.6	30.5	33.3	29.7	33.9	27.1
(9) Scheduled Maintenance (MW)	1,400	1,199	959	1,919	320	2,042	1,084	1,083
(10) Capability after Maintenance (MW) (6-9)	27,076	30,773	29,871	31,230	30,510	32,320	32,172	34,492
(11) Reserves after Maintenance (MW) (10-2)	5,968	5,994	7,299	5,820	7,381	5,824	7,339	6,496
(12) Reserves after Maintenance (%) (11÷2) x 100	28.3	24.2	32.3	22.9	31.9	22.0	29.6	23.2
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	27,076	30,773	29,871	31,230	30,510	32,320	32,172	34,492
(15) Available Reserve (MW) (14-2)	5,968	5,994	7,299	5,820	7,381	5,824	7,339	6,496
(16) Available Reserve (%) (15÷2) x 100	28.3	24.2	32.3	22.9	31.9	22.0	29.6	23.2
(17) Forced Outages (F.O.) (MW) 2/	3,759	4,476	3,759	4,476	3,759	4,476	3,759	4,476
(18) Available Capability after F.O. (MW) (14-17)	23,317	26,297	26,112	26,754	26,751	27,844	28,413	30,016
(19) Actual Reserve (MW) (18-2)	2,209	1,518	3,540	1,344	3,622	1,348	3,580	2,020
(20) Actual Reserve (%) (19÷2) x 100	10.5	6.1	15.7	5.3	15.7	5.1	14.4	7.2

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the ERA Field Office Staff

3/ () denotes negative number

XI.7.45

Table 7C.10

FUTURE CAPABILITY AND RESERVE MARGINS
TENNESSEE VALLEY AUTHORITY GROUP REGION

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	34,356	35,760	36,874	36,993	39,340	39,459	40,625	40,744	41,858	43,210
(2) Peak Demand (MW)	25,395	28,579	26,039	29,305	26,775	30,087	27,545	30,880	28,292	31,752
(3) Planned Reserve (MW) (1-2)	8,961	7,181	10,835	7,688	12,565	9,372	13,080	9,864	13,566	11,458
(4) Planned Reserve (%) (3÷2) x 100	35.3	25.1	41.6	26.2	46.9	31.1	47.5	31.9	47.9	36.1
(5) Net Transactions 1/ (MW)	(1,100)	1,100	(1,100)	1,100	(1,100)	1,100	(1,100)	1,100	(1,100)	1,100
(6) Total Capability (MW) (1+5)	33,256	36,860	35,774	38,093	38,240	40,559	39,525	41,844	40,758	44,310
(7) Total Reserve (MW) (6-2)	7,861	8,281	9,735	8,788	11,465	10,472	11,980	10,964	12,466	12,558
(8) Total Reserve (%) (7÷2) x 100	31.0	29.0	37.4	30.0	42.8	34.8	43.5	35.5	44.1	39.6
(9) Scheduled Maintenance (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(10) Capability after Maintenance (MW) (6-9)	33,256	36,860	35,774	38,093	38,240	40,559	39,525	41,844	40,758	44,310
(11) Reserve after Maintenance (MW) (10-2)	7,861	8,281	9,735	8,788	11,465	10,472	11,980	10,964	12,466	12,558
(12) Reserve after Maintenance (%) (11÷2) x 100	31.0	29.0	37.4	30.0	42.8	34.8	43.5	35.5	44.1	39.6
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	33,256	36,860	35,774	38,093	38,240	40,559	39,525	41,844	40,758	44,310
(15) Available Reserve (MW) (14-2)	7,861	8,281	9,735	8,788	11,465	10,472	11,980	10,964	12,466	12,558
(16) Available Reserve (%) (15÷2) x 100	31.0	29.0	37.4	30.0	42.8	34.8	43.5	35.5	44.1	39.6
(17) Forced Outages (F.O.) (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(18) Available Capability after F.O. (MW) (14-17)	33,256	36,860	35,774	38,093	38,240	40,559	39,525	41,844	40,758	44,310
(19) Actual Reserve (MW) (18-2)	7,861	8,281	9,735	8,788	11,465	10,472	11,980	10,964	12,466	12,558
(20) Actual Reserve (%) (19÷2) x 100	31.0	29.0	37.4	30.0	42.8	34.8	43.5	35.5	44.1	39.6

1/ Net Transactions = Purchases - Sales

2/ Information on scheduled maintenance and forced outages are not available

() denotes negative number

VACAR SUBREGIONHistorical Perspective

The VACAR Subregion contains the greatest amount of installed dependable capacity of the four subregions making up the Southeastern Electric Reliability Council. Included in this capacity is 7,317 MW of nuclear units representing 33 percent of the SERC total and 15 percent of the total installed in the contiguous United States. The VACAR Subregion also has the first nuclear unit installed in the Southeast, the Robinson No. 2 (700 MW) of Carolina Power and Light Company.

For the years from 1960 through 1975 the VACAR Subregion had a vigorous load growth rate of about 8.9 percent per year. There appears to be, however, a leveling off for the three years covered in the Historical Perspective with an average growth rate of 2.1 percent for the summer peak demand and 1.5 percent for the winter peak demand. The figures below also show that there is little difference between the summer and winter peak demands.

TABLE 7D.1

Actual Annual Net Energy For Load, Summer and
Winter Peak Demands and Load Factors 1/
Virginia-Carolinas Group Region

<u>Item</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy in GWh	136,911	142,084	143,995
Summer Peak Demand in MW	26,370	26,200	27,494
Winter Peak Demand in MW <u>2/</u>	25,814	26,063	26,627
Annual Load Factor in %	59.3	61.9	59.8

 1/ Source - Form No. 12E-2.

2/ Winter period for each year includes December of that year plus January and February of the following year.

Using 1978 as a typical year in the three-year study period, the nuclear units had a net generation of 43,894 GWh or 31 percent of the total net generation for the Subregion. This energy produced by 20.7 percent of the installed capacity, represents a 68.5 percent plant factor. As shown on Table 7D.2 the coal units and nuclear units produced 81.3 percent of the net generation with a combined plant factor of 54.1 percent and made up 69.5 percent of the installed capacity.

TABLE 7D.2

Actual 1978 Summer Generating Capacity by Fuel Type
Virginia-Carolinas Group Region

<u>Capacity Type</u>	<u>Fuel Type</u>	<u>Capacity</u>		<u>Generation</u>	
		<u>MW</u>	<u>% of Total</u>	<u>GWH</u>	<u>% of Total</u>
Steam	Coal	17,245	48.8	72,509	50.6
Steam	Nuclear	7,317	20.7	43,894	30.6
Steam	Oil	4,267	12.1	18,917	13.2
Steam	Gas	0	0	0	0
Hydro	Water	2,463	6.9	7,052	4.9
Pumped Storage	Water	1,122	3.2	(152) <u>1/</u>	(0.1) <u>1/</u>
Gas Turbine	Oil	2,400	6.8	833	0.6
Gas Turbine	Gas	265	0.7	109	0.1
Combined Cycle	Oil	282	0.8	70	0.1
Combined Cycle	Gas	0	0	0	0
Other		<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Total		35,361	100.0	143,232	100.0

1/ () Denotes negative number.

XI.7.49

Planned reserve criteria for VACAR utilities generally ranges from 15 to 20 percent of peak demand. Operating reserve 1/ is coordinated among the VACAR companies. By agreement, each member system maintains operating reserve of four percent of the annual peak demand plus eight percent of the largest generating unit. The largest generating unit is currently 1,140 MW. Using the reported data for 1978 the operating reserve would be as follows:

1978 Peak demand <u>2/</u> 26,200 (Aug.) x .04	= 1,048 MW
CP&L Unit - Brunswick No. 1 - 790 x .08	= 63.2 ,W
Duke Unit - Bellows Creek No. 1 - 1140 x .08	= 91.2 MW
SCE&G Unit - Williams No. 1 - 580 x .08	= 46.4 MW
SCPSA Unit - Winyah No. 1 - 280 x .08	= 22.4 MW
VEPCO Unit - Surry No. 1 - 775 x .08	= 62.0 MW
Yadkin Unit - Narrows No. 1 - 24 x .08	= <u>1.9</u> MW
Total	1,335 MW

Tables 7D.3 through 7D.5 show the historical reserve margins for 1977 through 1979. As shown in Table 7D.3, actual reserve in January of 1978 was 689 MW, or 2.7 percent. For the same month, there was 6,571 MW of forced outages (Item 17) in addition to the 1,783 MW capacity scheduled for maintenance. If half of the capacity shown in Item (17) were available the resultant actual reserve would have been a comfortable 15.6 percent instead of 2.7 percent. The forced outages shown on Tables 7D.3-7D.5 ranges from a low of 4,299 MW to a high of 7,071 MW. While these two extreme unavailable capacities formed 16.1 percent and 29.8 percent of the peak demand respectively, the corresponding actual reserves were 6 percent and 12.4 percent respectively. It could be assumed that due to the large amount of nuclear capacity in this Subregion that much of the capacity was unavailable due to various checks, inspections and other regulatory requirements. As the "Three Mile Island Lessons Learned" program is completed, a substantial reduction in forced outages may be noted.

The transmission to generating capacity ratio in VACAR for 1978 was about 115 MW miles per MW. There were 1,300 miles of 500 kV lines, 5,200 miles of 230kV lines and 10,600 miles of 100 to 132kV lines in operation in 1978 with a transmission capability of about 3.9 million MW miles.

1/ Reserve after maintenance.

2/ Total VACAR Subregion

Although VACAR does not operate as a power pool or dispatch economy energy on coordinated basis, it is one of the most thermally efficient electric regions in the country. Table 7D.6 gives the resulting steam-electric heat rates by major systems in VACAR for 1977.

TABLE 7D.6

Steam-Electric Heat Rates by Major Systems
Virginia-Carolinas Group Region

<u>System</u>	<u>Heat Rate</u> <u>Btu/kWh</u>
Carolina Power and Light	10,009
Duke Power Company	9,451
South Carolina Electric and Gas Company	9,952
South Carolina Public Service Authority	10,000
Virginia Electric and Power Company	<u>10,779</u>
VACAR	9,996

Current Perspective

The peak demand in the VACAR Subregion for the summer of 1980 is projected to be 28,353 MW. This is an increase of 3 percent over the previous year and is slightly higher than the average annual growth rate of 2.1 percent over the previous three years. The 1980 winter peak demand is expected to be 28,128 MW, an increase of 5.3 percent over the previous winter. It is anticipated that by the mid-1980's, the Subregion will be a winter peaking area.

The total reserve for this period is expected to range from 8,182 MW to 9,951 (29.3 to 39.4 percent) for the summer months, and 9,933 MW to 11,757 MW (35.3 to 44.7 percent) for the winter months. If the in-service dates for McGuire No. 1 and North Anna No. 2 nuclear units slip beyond the 1980 summer season, the total reserve still would exceed the 15-20 percent VACAP criteria. Reserve after maintenance however, will vary from a low of 5,106 MW (20.2 percent) in June, to a high of 7,852 MW (27.7 percent) in August. Again it should be noted that if the above two nuclear units are not available, the August reserve decreases by 2,087 MW, leaving a 20.3 percent reserve margin.

While the total reserve and reserve after maintenance situation appear to be adequate, the actual reserve based on the historic data for the previous three years, are somewhat tenuous. The historic data show that during the peak seasons, 15-16 percent of the dependable capacity was experiencing forced outage problems. Assuming that this condition could continue in 1980, Table 7D.7 shows that June and possibly July would be critical periods if all other items in this Table remain unchanged.

The non-simultaneous import capabilities for VACAR are shown in Table 7D.8.

TABLE 7D.8

Non-Simultaneous Import Capabilities
Virginia-Carolinas Group Region

<u>Transfer Parties</u>	<u>Emergency Transfer Capability-MW</u>
Southern to VACAR	1,700
TVA to VACAR .	2,200
ECAR to VACAR	2,200
MAAC to VACAR	1,800

In addition to the emergency transfer capabilities, VACAR is able to obtain emergency load relief in the following manner:

<u>Option</u>	<u>Estimated MW Relief</u>
Curtailment of non-essential utility system load	12
Interruption of interruptible contract system load	142
Voltage reduction--5%	586
Public appeals for voluntary conservation	<u>828 1/</u>
Total	1,568

1/ Public Appeals for Voluntary Conservation = (28,353 MW Summer Peak - 12 MW - 142 MW - 586 MW) x .03 = 828 MW.

The 1,568 MW emergency load relief amounts to 5.5 percent of the anticipated 1980 summer peak load.

Future Perspective

The VACAR Subregion is forecasting the annual electric energy use to increase from 151,578 GWh in 1980 to 231,770 GWh in 1989. This represents an average growth rate of 4.8 percent and is approximately twice the average annual growth rate of 2.5 percent recorded during the 1977 through 1979 period. The past three years, however, could be reflecting some initial conservation on part of the consumer which after a period of adjustment may not continue as noticeably. The summer peak demand is estimated to grow from 28,353 MW in 1980 to 43,433 MW in 1989. This annual growth rate of 4.8 percent reflects a reduction from the annual growth rate of 6.5 percent which was projected in 1977. The actual summer peak demand growth rate for the past three years was 2.0 percent. The winter peak demand is estimated to increase from 28,128 MW in 1980 to 43,458 MW in 1989. The winter growth rate of 4.9 percent is slightly higher than the summer rate of 4.8 percent and by 1987 the Subregion will be a winter peaking area.

Assuming that current projections for load growth and the resultant need for additional capacity are realistic, the VACAP Subregion will continue to have the greatest amount of nuclear capacity during the 1980's. The capacity mix as currently planned (see Table 7D.9) shows that nuclear units increase from 22.8 percent in 1980 to 35.2 percent in 1989 of the generating capacity in the Subregion.

TABLE 7D.9

Mid-year Generating Capacity
Virginia-Carolinas Group Region

Unit-Fuel Type	1980		1984		1989	
	MW	% of Total	MW	% of Total	MW	% of Total
ST-NU	8,171	22.8	13,476	30.4	18,235	35.2
ST-Coal	17,258	48.3	19,448	43.9	22,068	42.6
ST-Oil	4,194	11.8	4,194	9.5	4,194	8.1
ST-Gas	0	0.0	0	0.0	0	0.0
Hydro	2,475	6.9	2,515	5.7	2,749	5.3
PS	1,122	3.1	2,172	4.9	2,172	4.2
GT-Oil	2,010	5.6	2,010	4.5	1,807	3.5
GT-Gas	249	0.7	249	0.5	249	0.5
CC-Oil	282	0.8	282	0.6	282	0.6
CC-Gas	0	0.0	0	0.0	0	0.0
Other	0	0.0	0	0.0	0	0.0
Total	35,761	100.0	44,346	100.0	51,756	100.0

Historically, the nuclear units in the VACAP Subregion have produced more energy per installed MW of capacity than any other type of unit and operate at a plant factor as high as 70 percent. The effect of slippage for the in-service dates for the planned nuclear units is shown on Table 7D.10

TABLE 7D.10

Effect of Construction Slippage for Planned Nuclear Unit Additions
Virginia-Carolinas Group Region

Current Schedule of Planned Nuclear Additions

	<u>1980</u>	<u>1984</u>	<u>1989</u>
Planned Capability (MW)	35,761	44,346	51,756
Summer Peak Demand (MW)	28,447	34,904	43,433
Planned Reserve (MW)	7,314	9,442	8,323
Planned Reserve (%)	25.7	27.1	19.2

One-Year Slippage of Planned Nuclear Additions

	<u>1980</u>	<u>1984</u>	<u>1989</u>
Planned Capability (MW)	34,863 <u>1/</u>	42,301 <u>2/</u>	49,949 <u>3/</u>
Summer Peak Demand (MW)	28,447	34,904	43,433
Planned Reserve (MW)	6,416	7,397	6,516
Planned Reserve (%)	22.6	21.2	15.0

-
- 1/ North Anna-2 (898 MW) not available.
2/ Harris-1 (900 MW) not available.
 Catawba-1 (1,145 MW) not available.
3/ North Anna-4 (907 MW) not available.
 Harris-4 (900 MW) not available.

The impact of slippage can be noted when it is compared to the Mid-year Generating Capacity summary (Table 7D.9). If all the non-oil/gas units were ideally available for the summer of 1989, the planned reserve would amount to 1,791 MW. With the slippage of the two nuclear units, 1/ there would be a deficiency of 16 MW. Based on practical expectations and/or historical records, there will always be a dependence on the oil/gas units to meet unusual load conditions, a dependence that increases with in-service date slippage. Such a condition is contrary to the national commitment to reduce oil consumption.

There is another condition to be considered when examining electric supply and demand. As noted previously, the forecast growth rate has decreased from 6.5 percent in 1977 to 4.8 percent in 1980. At this time, the 1980 forecast appears to be a reasonable one for planning purposes. If, however, the actual growth rate is less, say 3.8 percent, the peak demand would be reduced by 1,880 MW in 1984 and 3,649 MW in 1989. This would negate the effects of unit slippage and perhaps lead to a re-evaluation of the need and types of new capacity.

Each member of VACAR has its own planned reserve criteria which generally ranges from 15 to 20 percent of the projected peak load. Except for the summer of 1989, VACAR exceeds the upper criteria in all peak seasons between 1981 and 1989 (see Table 7D.11). Study of the summer of 1989 peak season shows that a delay in the in-service date for North Anna No. 4 (907 MW) and Harris No. 4 (900 MW) units will result in a minimum planned reserve of 15 percent.

In 1981, the largest unit in the Subregion will be McGuire No. 1, 1,180 MW nuclear unit, scheduled for operation in December 1980. The second largest unit in 1981 will be the existing Bellews Creek, 1,120 MW coal-fired unit (there are two 1,120 MW units at Bellews Creek). In July 1982 the McGuire No. 2, 1,180 MW nuclear unit is scheduled to become operational.

1/ Harris No. 4 (900 MW), and North Anna No. 4 (907 MW).

Based on the VACAR criteria for operational or spinning reserve of 4 percent of the estimated peak load plus 8 percent of the rating of each member's largest unit, there will be a low requirement of 1,477 MW in the summer of 1981 to a high requirement of 1,683 MW in the summer of 1984 of operating reserve. This equates to the largest unit plus 297 MW in 1981 and the largest unit plus 503 MW in 1984. Planned reserve after maintenance exceeds the operating reserve requirement by at least 5,000 MW between 1981 and 1984. This should be adequate to cover unexpected forced outages of generating equipment.

Table 7D.12 shows the projected energy requirements, anticipated seasonal demands and annual load factors for the beginning year mid-year, and the last year of the study period.

TABLE 7D.12

Projected Energy Requirements, Anticipated
Seasonal Demands and Annual Load Factors
Virginia-Carolinias Group Region

<u>Item</u>	<u>1980</u>	<u>1984</u>	<u>1989</u>
Annual Electric Energy in GWh	151,578	185,340	231,770
Summer Peak Demand in MW	28,447	34,904	43,433
Winter Peak Demand in MW	28,125	34,714	43,458
Annual Load Factor in %	60.7	60.5	60.9

By the end of 1979, the bulk power transmission system in the VACAP Subregion consisted of approximately 5,866 miles of 230 kV, 1,475 miles of 500 kV and 10,600 miles of 100 to 132kV. To this existing system the following sequence of additions are planned through 1989:

Additional Transmission Lines in Miles

	<u>230 kV</u>	<u>500 kV</u>
1980	611	0
1981	488	86
1982	455	133
1983	127	276
1984	362	0
1985	194	0
1986	201	94
1987	402	72
1988	218	177
1989	<u>330</u>	<u>107</u>
Total	3,388	945

The transmission additions above to generating capacity addition during the same period amounts to 124 MW miles per MW. By the end of 1989 the VACAR Subregion will have a planned transmission capability of 5.2 million megawatt miles.

The in-service dates for the majority of the planned generating unit additions during 1980-1989 period have slipped for a total of 228,240 MW-months. The greatest portion of this slippage occurred in nuclear units with a total of 175,740 MW-months. Of this amount, 139,980 MW-months is identified with four of the seven units delayed. There is 1,800 MW of nuclear capacity still on schedule. In-service dates for six coal units have slipped for a total of 63,960 MW-months, while in-service dates for two units have advanced 11,460 MW-months for a net slippage of 52,500 MW-months. A ninth coal unit of 720 MW capacity is on schedule. Since most of the slippage occurs after 1985 and the subregion is predominantly of coal and nuclear capacity, the slippage may not be critical from an intra-subregion fuel use standpoint. The effects of delays of in-service dates from the load-supply standpoint, would be dependent on the load growth in the next few years.

Table 7D.3

HISTORICAL CAPABILITY AND RESERVE MARGINS
VIRGINIA-CAROLINAS GROUP REGION

	1977 Summer			1977/1978 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	32,468	32,748	32,733	33,339	33,339	33,306
(2) Peak Demand (MW)	23,686	26,370	25,486	23,453	25,441	25,814
(3) Planned Reserve (MW) (1-2)	8,782	6,378	7,247	9,886	7,898	7,492
(4) Planned Reserve (%) (3÷2) x 100	37.1	24.2	28.4	42.2	31.0	29.0
(5) Net Transactions 1/ (MW)	243	2,720	1,858	1,127	1,145	589
(6) Total Capability (MW) (1+5)	32,711	35,468	34,591	34,466	34,484	33,895
(7) Total Reserve (MW) (6-2)	9,025	9,098	9,105	11,013	9,043	8,081
(8) Total Reserve (%) (7÷2) x 100	38.1	34.5	35.7	47.0	35.5	31.3
(9) Scheduled Maintenance (MW)	2,359	1,292	867	2,460	1,783	2,473
(10) Capability After Maintenance (MW) (6-9)	30,352	34,176	33,724	32,006	32,701	31,422
(11) Reserve After Maintenance (MW) (10-2)	6,666	7,806	8,238	8,553	7,260	5,608
(12) Reserve After Maintenance (%) (11÷2) x 100	28.1	29.5	32.3	36.5	28.5	21.7
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	30,352	34,176	33,724	32,006	32,701	31,422
(15) Available Reserve (MW) (14-2)	6,666	7,806	8,238	8,553	7,260	5,608
(16) Available Reserve (%) (15÷2) x 100	28.1	29.6	32.3	36.5	28.5	21.7
(17) Forced Outages (F.O.) (MW)	4,508	5,646	5,978	6,709	6,571	4,448
(18) Available Capability After F.O. (MW) (14-17)	25,844	28,530	27,746	25,297	26,130	26,974
(19) Actual Reserve (MW) (18-2)	2,158	2,160	2,260	1,844	689	1,160
(20) Actual Reserve (%) (19÷2) x 100	9.1	8.2	8.9	7.9	2.7	4.5

1/ Net Transactions = Purchases - Sales

Table 7D.4

HISTORICAL CAPABILITY AND RESERVE MARGINS
VIRGINIA-CAROLINAS GROUP REGION

	1978 Summer			1978/1979 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	33,864	33,892	33,892	34,513	34,768	34,768
(2) Peak Demand (MW)	25,750	26,006	26,200	23,753	26,063	25,943
(3) Planned Reserve (MW) (1-2)	8,114	7,886	7,692	10,760	8,705	8,825
(4) Planned Reserve (%) (3÷2) x 100	31.5	30.3	29.4	45.3	33.4	34.0
(5) Net Transactions ^{1/} (MW)	2,014	1,530	2,178	414	289	1,528
(6) Total Capability (MW) (1+5)	35,878	35,422	36,070	34,927	35,057	36,296
(7) Total Reserve (MW) (6-2)	10,128	9,416	9,870	11,174	8,994	10,353
(8) Total Reserve (%) (7÷2) x 100	39.3	36.2	37.7	47.0	34.5	39.9
(9) Scheduled Maintenance (MW)	2,484	1,490	1,828	2,669	1,252	1,992
(10) Capability After Maintenance (MW) (6-9)	33,394	33,932	34,242	32,258	33,805	34,304
(11) Reserve After Maintenance (MW) (10-2)	7,644	7,926	8,042	8,505	7,742	8,361
(12) Reserve After Maintenance (%) (11÷2) x 100	29.7	30.5	30.7	35.8	29.7	32.2
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	33,394	33,932	34,242	32,258	33,805	34,304
(15) Available Reserve (MW) (14-2)	7,644	7,926	8,042	8,505	7,742	8,361
(16) Available Reserve (%) (15÷2) x 100	29.7	30.5	30.7	35.8	29.7	32.2
(17) Forced Outages (F.O.) (MW)	6,233	5,325	5,505	7,071	6,033	5,777
(18) Available Capability After F.O. (MW) (14-17)	27,161	28,607	28,737	25,187	27,772	28,527
(19) Actual Reserve (MW) (18-2)	1,411	2,601	2,537	1,434	1,709	2,584
(20) Actual Reserve (%) (19÷2) x 100	5.5	10.0	9.7	6.0	6.6	10.0

^{1/} Net Transactions = Purchases - Sales

Table 7D.5

HISTORICAL CAPABILITY AND RESERVE MARGINS
VIRGINIA-CAROLINAS GROUP REGION

	1979 Summer			1979/1980 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	34,300	34,195	34,195	34,540	34,492	34,498
(2) Peak Demand (MW)	22,474	25,475	27,494	24,806	24,774	26,627
(3) Planned Reserve (MW) (1-2)	11,826	8,720	6,701	9,734	9,718	7,871
(4) Planned Reserve (%) (3÷2) x 100	52.6	34.2	24.4	39.2	39.2	29.6
(5) Net Transactions 1/ (MW)	1,511	3,079	2,309	2,227	2,000	2,894
(6) Total Capability (MW) (1+5)	35,811	37,274	36,504	36,767	36,492	37,392
(7) Total Reserve (MW) (6-2)	13,337	11,799	9,010	11,961	11,718	10,765
(8) Total Reserve (%) (7÷2) x 100	59.3	46.3	32.8	48.2	47.3	40.4
(9) Scheduled Maintenance (MW)	5,244	3,744	6,285	4,896	2,845	3,158
(10) Capability After Maintenance (MW) (6-9)	30,567	33,530	30,219	31,871	33,647	34,234
(11) Reserve After Maintenance (MW) (10-2)	8,093	8,055	2,725	7,065	8,873	7,607
(12) Reserve After Maintenance (%) (11÷2) x 100	36.0	31.6	9.9	28.5	35.8	28.6
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	30,567	33,530	30,219	31,871	33,647	34,234
(15) Available Reserve (MW) (14-2)	8,093	8,055	2,725	7,065	8,873	7,607
(16) Available Reserve (%) (15÷2) x 100	36.0	31.6	9.9	28.5	35.8	28.6
(17) Forced Outages (F.O.) (MW)	4,889	6,285	5,431	4,847	5,042	4,299
(18) Available Capability After F.O. (MW) (14-17)	25,678	27,245	24,788	27,024	28,605	29,935
(19) Actual Reserve (MW) (18-2)	3,204	1,770	(2,706) 2/	2,218	3,831	3,308
(20) Actual Reserve (%) (19÷2) x 100	14.3	7.0	(9.8) 2/	8.9	15.5	12.4

1/ Net Transactions = Purchases - Sales

2/ () denotes negative number

Table 7D.7

CURRENT CAPABILITY AND RESERVE MARGINS
VIRGINIA-CAROLINAS GROUP REGION

	1980 Summer			1980/1981 Winter		
	June	July	August	December	January	February
(1) Planned Capability (MW)	34,344	35,242	36,422	37,818	37,818	37,818
(2) Peak Demand (MW)	25,236	27,903	28,353	26,304	28,128	26,976
(3) Planned Reserve (MW) (1-2)	9,108	7,339	8,069	11,514	9,690	10,842
(4) Planned Reserve (%) (3÷2) x 100	36.1	26.3	28.5	43.8	34.5	40.2
(5) Net Transactions 1/ (MW)	843	843	843	243	243	243
(6) Total Capability (MW) (1+5)	35,187	36,085	37,265	38,061	38,061	38,061
(7) Total Reserve (MW) (6-2)	9,951	8,182	8,912	11,757	9,933	11,085
(8) Total Reserve (%) (7÷2) x 100	39.4	29.3	31.4	44.7	35.3	41.1
(9) Scheduled Maintenance (MW)	4,845	2,045	1,060	2,275	1,845	2,786
(10) Capability After Maintenance (MW) (6-9)	30,342	34,040	36,205	35,786	36,216	35,275
(11) Reserve After Maintenance (MW) (10-2)	5,106	6,137	7,852	9,482	8,088	8,299
(12) Reserve After Maintenance (%) (11÷2) x 100	20.2	22.0	27.7	36.1	28.8	30.8
(13) Inoperable Capability (MW)	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	30,342	34,040	36,205	35,786	36,216	35,275
(15) Available Reserve (MW) (14-2)	5,106	6,137	7,852	9,482	8,088	8,299
(16) Available Reserve (%) (15÷2) x 100	20.2	22.0	27.7	36.1	28.8	30.8
(17) Forced Outages (F.O.) (MW) 2/	5,533	5,533	5,533	5,663	5,663	5,663
(18) Available Capability After F.O. (MW) (14-17)	24,809	28,507	30,672	30,123	30,553	29,612
(19) Actual Reserve (MW) (18-2)	(427) 3/	604	2,319	3,819	2,425	2,636
(20) Actual Reserve (%) (19÷2) x 100	(1.7)	2.2	8.2	14.5	8.6	9.8

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the ERA Field Office Staff

3/ () denotes negative number

Table 7D.11

FUTURE CAPABILITY AND RESERVE MARGINS 1981-1984
VIRGINIA-CAROLINAS GROUP REGION

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1) Planned Capability (MW)	38,861	39,538	40,041	40,718	40,761	43,598	44,346	45,173
2) Peak Demand (MW)	39,774	40,157	31,966	31,572	33,374	33,079	34,904	34,714
3) Planned Reserve (MW) (1-2)	9,787	9,381	8,075	9,146	7,387	10,519	9,442	10,459
4) Planned Reserve (%) (3÷2) x 100	30.5	31.1	25.3	29.0	22.1	31.8	27.1	30.1
5) Net Transactions 1/ (MW)	300	(300) 3/	300	(300) 3/	300	(300) 3/	300	(300) 3/
6) Total Capability (MW) (1+5)	39,161	39,238	40,341	40,418	41,061	43,298	44,646	44,873
7) Total Reserve (MW) (6-2)	9,387	9,381	8,375	8,846	7,687	10,219	9,742	10,159
8) Total Reserve (%) (7÷2) x 100	31.5	30.1	26.2	28.0	23.0	30.9	27.9	29.3
9) Scheduled Maintenance (MW)	64	1,533	150	2,460	215	1,180	193	1,273
10) Capability After Maintenance (MW) (6-9)	39,097	37,505	40,191	37,958	40,846	42,118	44,453	43,600
11) Reserve After Maintenance (MW) (10-2)	9,323	7,448	8,225	6,386	7,472	9,039	9,549	8,886
12) Reserve After Maintenance (%) (11÷2) x 100	31.3	24.7	25.7	20.2	22.4	27.3	27.4	25.6
13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0
14) Available Capability (MW) (10-13)	39,097	37,505	40,191	37,958	40,846	42,118	44,453	43,600
15) Available Reserve (MW) (14-2)	9,323	7,448	8,225	6,386	7,472	9,039	9,549	8,886
16) Available Reserve (%) (15÷2) x 100	31.3	24.7	25.7	20.2	22.4	27.3	27.4	25.6
17) Forced Outages (F.O.) (MW) 2/	5,533	5,563	5,533	5,663	5,533	5,663	5,533	5,663
18) Available Capability After F.O. (MW) (14-17)	33,564	31,942	34,658	32,295	35,313	36,455	38,920	37,937
19) Actual Reserve (MW) (18-2)	3,790	1,785	2,692	723	1,939	3,376	4,016	3,223
20) Actual Reserve (%) (19÷2) x 100	12.7	5.9	8.4	2.3	5.8	10.2	11.5	9.3

1/ Net Transactions = Purchases - Sales

2/ Derived from the historic seasonal forced outage rate by the ERA Field Office Staff

3/ () denotes negative number

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Table 7D.11

FUTURE CAPABILITY AND RESERVE MARGINS
VIRGINIA-CAROLINAS GROUP REGION

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
(1) Planned Capability (MW)	46,445	46,987	46,510	47,544	48,267	49,851	49,996	51,033	51,756	52,325
(2) Peak Demand (MW)	36,531	36,390	38,149	38,100	39,869	39,902	41,635	41,701	43,433	43,458
(3) Planned Reserve (MW) (1-2)	9,914	10,597	8,361	9,444	8,398	9,949	8,361	9,332	8,323	8,867
(4) Planned Reserve (%) (3÷2) x 100	27.1	29.1	21.9	24.8	21.1	24.9	20.1	22.4	19.2	20.4
(5) Net Transactions 1/ (MW)	300	(300)	0	0	0	0	0	0	0	0
(6) Total Capability (MW) (1+5)	46,745	46,687	46,510	47,544	48,267	49,851	49,996	51,033	51,756	52,325
(7) Total Reserve (MW) (6-2)	10,214	10,297	8,361	9,444	8,398	9,949	8,361	9,332	8,323	8,867
(8) Total Reserve (%) (7÷2) x 100	28.0	28.3	21.9	24.8	21.1	24.9	20.1	22.4	19.2	20.4
(9) Scheduled Maintenance (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(10) Capability after Maintenance (MW) (6-9)	46,745	46,687	46,510	47,544	48,267	49,851	49,996	51,033	51,756	52,325
(11) Reserve after Maintenance (MW) (10-2)	10,214	10,297	8,361	9,444	8,398	9,949	8,361	9,332	8,323	8,867
(12) Reserve after Maintenance (%) (11÷2) x 100	28.0	28.3	21.9	24.8	21.1	24.9	20.1	22.4	19.2	20.4
(13) Inoperable Capability (MW)	0	0	0	0	0	0	0	0	0	0
(14) Available Capability (MW) (10-13)	46,745	46,687	46,510	47,544	48,267	49,851	49,996	51,033	51,756	52,325
(15) Available Reserve (MW) (14-2)	10,214	10,297	8,361	9,444	8,398	9,949	8,361	9,332	8,323	8,867
(16) Available Reserve (%) (15÷2) x 100	28.0	28.3	21.9	24.8	21.1	24.9	20.1	22.4	19.2	20.4
(17) Forced Outages (F.O.) (MW)	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
(18) Available Capability after F.O. (MW) (14-17)	46,745	46,687	46,510	47,544	48,267	49,851	49,996	51,033	51,756	52,325
(19) Actual Reserve (MW) (18-2)	10,214	10,297	8,361	9,444	8,398	9,949	8,361	9,332	8,323	8,867
(20) Actual Reserve (%) (19÷2) x 100	28.0	28.3	21.9	24.8	21.1	24.9	20.1	22.4	19.2	20.4

1/ Net Transactions = Purchases - Sales

2/ Information on scheduled maintenance and forced outages are not available
() denotes negative number

TABLE 7D.13

Major Future Generating Unit In-Service Dates
Virginia-Carolinas Group Region

<u>Unit Designation</u>	<u>Capacity MW</u>	<u>Fuel Type</u>	<u>In-Service Date</u>		<u>Change in MW-months</u>
			<u>As of 4/79</u>	<u>As of 4/80</u>	
North Anna No. 2	907	Nuc.	7/79	7/80	10,884
McGuire No. 1	1,180	Nuc.	1/80	8/80	8,260
Roxboro No. 4	720	Coal	3/80	9/80	4,320
Summer No. 1	900	Nuc.	12/80	12/80	0
Winyah No. 4	280	Coal	5/82	5/81	(3,360)
McGuire No. 2	1,180	Nuc.	7/81	7/82	14,160
Mayo No. 1	720	Coal	3/82	3/83	8,640
Harris No. 1	900	Nuc.	3/84	3/84	0
Catawba No. 1	1,145	Nuc.	1/82	12/83	26,335
Cross Site No. 2	450	Coal	5/85	11/83	(8,100)
Mayo No. 2	720	Coal	3/85	3/85	0
Catawba No. 2	1,145	Nuc.	7/83	7/85	27,480
Harris No. 2	900	Nuc.	3/86	3/87	10,800
Plant "A"	500	Coal	5/85	5/87	12,000
Cross Site No. 1	450	Coal	5/83	11/86	18,900
North Anna No. 3	907	Nuc.	10/83	10/87	43,536
North Anna No. 4	907	Nuc.	9/84	8/88	42,629
Harris No. 4	900	Nuc.	3/88	3/89	10,800
Plant "B"	500	Coal	5/87	5/89	12,000
Cross Site No. 3	450	Coal	5/87	11/88	8,100

SECTION XI.8
SOUTHWEST POWER POOL
(SPP)

Southwest Power PoolIntroduction

The Southwest Power Pool (SPP) area includes all of the states of Arkansas, Kansas, Louisiana and Oklahoma and part of the states of Mississippi, Missouri, New Mexico, and Texas, and serves a population of around 21,000,000. The SPP area is divided into four regions: Region 8 (Middle South Utilities Group), Region 10 (Gulf States Group), Region 21 (Missouri-Kansas Group), and Region 22 (Oklahoma Group).

Region 8 (Middle South Utilities Group) encompasses most of Arkansas, approximately one-half of both Mississippi and Louisiana, and a small portion of southeast Missouri. Approximately 95 percent of the electric load served in Region 8 is supplied by the Middle South Utilities Company, Inc. Middle South is a holding company consisting of Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Company and Arkansas-Missouri Power Company.

Region 10 (Gulf States Group) includes the southern portion of Louisiana, excluding the New Orleans area, and the east central portion of Texas that is within the SPP. Regions 8 and 10 are combined into a single group by SPP and systems operating within the two Regions coordinate their planning through the SPP planning Subcommittee.

Region 21 (Missouri-Kansas Group) covers almost the entire state of Kansas and the remaining part of Missouri that is in the SPP. The majority of the electric systems operating in Region 21 are members of the MOKAN Power Pool.

Region 22 (Oklahoma Group) covers the largest area of the four electric regions in SPP ranging from western Louisiana to eastern New Mexico. It includes all of Oklahoma and portions of Arkansas, Kansas, Louisiana, Texas, and New Mexico.

All Electric Regions within SPP experience their annual peak demand in the summer, usually during prolonged hot-dry periods called heat storms. The growth of peak demand for the entire

SPP has been declining since the early 1970's, and as a result, the systems have been revising and reducing their projected rate of growth annually. Table 8.1 shows projected rates of growth for summer and winter peak demands and annual energy as reported by SPP in its 1970, 1975 and 1980 reliability reports. The growth rates are for ten year periods.

Table 8.1

Compound Annual Growth Rate
Southwest Power Pool

<u>Report Year</u>	<u>Peak Demand</u>		<u>Annual Energy</u>
	<u>Summer</u> (%)	<u>Winter</u> (%)	
1970	10.7	10.1	13.4
1975	8.2	8.5	8.3
1980	5.1	5.3	5.3

Although each Electric Region in SPP has coal-fired generating units either in service or under construction, and one, Region 8, has two nuclear units in operation, the area is heavily dependent upon natural gas and oil for electric generation. During the year 1978 SPP obtained 59.2 percent of its electric generation from natural gas, 18.7 percent from fuel oil, 16.8 percent from coal, 2.7 percent from nuclear and 2.6 percent from hydroelectric plants. SPP burned 61,618,000 barrels of oil in 1978, 86.8 percent of which was residual oil. During the period 1980 through 1989 systems in SPP are projecting 27,215 megawatts of new coal-fired capacity, 6,311 megawatts combustion turbine and internal combustion capacity and 380 megawatts of capacity which is undecided. Tables 8.2 and 8.3 provide lists of projected coal-fired capacity and nuclear-fueled capacity, respectively.

The SPP has a backbone transmission system at the 500-kV level in Regions 8 and 10 and 345-kV in Regions 21 and 22. The 500-kV system was developed primarily to effect a 1,500 MW diversity interchange with the Tennessee Valley-Authority which commenced in June 1967. The interchange was reduced to 1,100 MW in 1979 and will be further decreased to 700 MW in 1981 and 200 MW in 1984.

The Central and South West Operating Company (Public Service Company of Oklahoma and Southwestern Electric Power Company in SPP and Central Power & Light Company and West Texas Utilities Company in ERCOT) made application to the F.E.R.C. on February 9, 1979, for an interconnection between SPP and ERCOT. The interconnecting lines proposed by Central & South West were shown on the map furnished by SPP in its 1980 ERA-411; however, they were not included in the list of proposed bulk lines in Item 5-B of ERA-411.

In the remainder of this report a four-part examination, consisting of historical perspective, current perspective, near-term future perspective, and long-term future perspective, is made for each electrical region in SPP. The historical section covers actual load and supply conditions in 1977 through 1979 for systems reporting on the monthly EIA Form 12E-2. The current near-term and long-term sections report the projected load and supply conditions for members of SPP gas, therefore, the coverage is not exactly synonymous. Table 8.4 provides a list of Form 12E-2 respondents and members of SPP and indicates the difference in coverage. In addition, the final section of each electric region text discusses peak demand and annual energy projections and the resulting annual load factors for the period 1980 through 1989.

Middle South Utilities Area (Region 8)Historical Perspective

Until the early 1970's, the Middle South area experienced high growth rates for both peak demand and energy. The compound annual growth rate from 1960 to 1976 was 9.6 percent. The following table illustrates the high rate of growth during the first twenty years of this period and the sharp decline in peak demand and energy requirements after 1970.

Table 8A.1

HISTORICAL COMPOUND ANNUAL GROWTH RATES
Middle South Utilities Group (Region 8)

Period	Compound Annual Growth Rate	
	Peak Demand (%)	Annual Energy (%)
1950-60	10.4	9.3
1960-70	10.2	10.2
1970-76	7.4	6.9

Due to the growth rate reductions experienced in the 1970's, projections of future requirements have been reduced annually for the last several years. The average compound rate of growth for the 1980-1989 period in Region 8 is approximately 5.5 percent (see Table 8A.8). This compares to a forecasted growth rate of 7.2 percent in 1979. The latest reduction indicates that the systems in Region 8 still anticipate substantial reductions in electric growth due to a number of factors all related to inflation.

Additional evidence of the decline in electric growth rates is shown by Table 8A.3, which provides summer and winter peak demands, annual energy requirements and annual load factors for the years 1977 through 1979. Annual growth rates for 1977 to 1978 and 1978 to 1979 are also shown.

Although much of the existing generating capacity in Region 8, which was originally designed to burn natural gas, has been either converted or adapted to burn oil, the area continues to obtain a majority of its electric generation from natural gas fuel.

The following table^{1/} shows the 1979 end-of-year installed capacity by fuel type and the resulting annual generation each fuel contributed:

Table 8A.2

HISTORICAL INSTALLED CAPACITY AS OF DECEMBER 1979
Middle South Utilities Group (Region 8)

Fuel Type	Installed Capacity		Annual Generation	
	(MW)	(% of Total)	(Gwh)	(% of Total)
Nuclear	902	7.1	3,873	8.9
Coal	39	0.3	153	0.3
Natural Gas	9,479	74.1	25,344	57.9
Oil	2,307	18.0	14,115	32.3
Hydro	65	0.5	252	0.6
Total	12,792	100.0	43,737	100.0

There are two operating nuclear units owned by Arkansas Power & Light Company, Arkansas Nuclear One Units No. 1 and No. 2. Unit No. 2 of Arkansas Nuclear One was placed in service on March 27, 1980.

Systems operating in Region 8 plan for a minimum total reserve of 16 percent of forecasted peak demand and in accordance with the SPP Coordination Agreement must maintain, with system capacity or contractual arrangements, actual reserves of 6 percent of peak demand, 3 percent of which must be spinning. During the past several years, systems in the Middle South Area have been experiencing a high amount of forced outages on their generating units, due primarily to the increased use of fuel oil in boilers designed for natural gas operation. Tables 8A.4.1 and 8A.4.2 provide the actual reserve situation which occurred in Region 8 for the summer and winter periods for 1977 through 1979. Capability out of service on forced outage during the summer peak periods varied from a low of 3.3 percent in August 1977 to a high of 22 percent in June 1979. During the last two (1978 and 1979) summer peak periods, Region 8 would have experienced negative actual reserves without the benefit of capacity purchases.

The Middle South has strong intra-regional and interregional interconnections at the 500 kV level. This backbone transmission system was developed mainly as a result of the diversity interchange agreement between the South Central Electric Companies and the Tennessee Valley Authority.

1/ Source of information is EIA-4 Form data, based on Form 12E-2 respondents.

Due in a large part to the escalation of fuel prices and the curtailment of natural gas supplies, Region 8 has been a net energy purchaser during the last three years. The net energy purchased during 1977, 1978, and 1979, was 5961 GWh, 7104 GWh and 15339 GWh, respectively. In terms of percent of energy for load, these purchases were 11.0 percent in 1977, 12.4 percent in 1978, and 25.8 percent in 1979.

Current Perspective

The Middle South Utilities Group is projecting to install the 740-MW White Bluff No. 1 coal-fired unit by the 1980 summer peak. Ninety-eight percent of the capacity belongs to the Middle South Group. Present information shows no delays in this in-service date.

Total installed reserves are projected to be 25.4 percent in the 1980 summer and 61.2 percent during the 1980/81 winter peak. No inoperable capability is expected and scheduled maintenance, performed in the winter, would result in available reserves of 25.4 percent and 39.9 percent for the summer and winter peaks, respectively. Estimated forced outages create actual reserves of 11.9 percent in the summer and 18.6 percent in the winter. All reserves are well above the SPP criteria for both planned and available reserves. Table 8A.5 shows the reserve situation for the 1980 summer peak and 1980/81 winter peak.

Excess capacity should be available to supply the Gulf States Group with emergency power if needed. (See the Gulf States group's current perspective for more detail.)

During the evening of April 8, 1980, tornadoes occurred in North Arkansas damaging approximately eighty-nine 500 kV towers and eighty 115- and 161-kV wood pole structures belonging to the Arkansas Power & Light Company. The Arkansas Nuclear One generating station (1748 MW) was shut down due to a lack of transmission out of the plant. Sufficient 161-kV circuits were restored within 12 days to operate Unit No. 2 at a reduced capacity of approximately 720 MW. The Company reports that repairs to transmission lines should be completed before the summer peaking season so that the full capability of the plant will be available during that period.

Future Perspective

The Middle South Utilities Group is projecting 1450 MW of coal-fired capacity and 2,235 MW of nuclear capacity in this time period.

Total (summer) reserves are projected to range from 20.9 percent to 34.9 percent (see Table 8A.6) which is well above the SPP criteria. Since Region 8 projects no scheduled maintenance or inoperable capability during the summer period, the available reserves are the same as total reserves. Actual reserves, which include 13.4 percent of forced outages based on historical summer trends, range from 7.5 to 21.5 percent. An NRC projected nuclear delay of the Waterford No. 3 nuclear unit beyond the 1982 summer peak would result in actual reserves from 7.5 percent to 17.4 percent (which appears to be adequate). With possible coal unit delays, the available reserves would range from 7.5 percent to 12.9 percent (also adequate).

The Middle South Group appears to have enough capacity to handle expected demand with possible forced outages and nuclear and coal-fired unit delays. The Region, however, may be needed to supply emergency power to the Gulf States Group (Region 10) during the 1981-1985 period as discussed in the Gulf States Perspective. Middle South and Gulf States should have enough existing and proposed interchange capability to allow the necessary emergency transfer of power during the peak periods. In addition to the proposed tie with Region 10, Middle South is projecting a 161-kV tie in 1981 with ILLMO (Region 17) to increase interchange capability. This tie will be increased in voltage to 500-kV in 1984.

The Middle South Utilities Group is projecting 3,725 MW of coal-fired capacity and 1,125 MW of nuclear capacity in the 1985-1989 period.

Reserve margins, not including the effects of scheduled maintenance and forced outages, would range from 16.3 to 26.4 percent, which should be adequate (see Table 8A.7). The Region would have enough excess capacity to handle forced outages based upon historical rates and should have enough reserve to help the Gulf States Group if necessary. There are no nuclear delays projected in this time period.

Interregional interchange capability should be increased with a proposed 500-kV tie with TVA in 1986.

It would appear that the Middle South Utilities Group would have ample capacity to supply all of its own load requirement throughout the decade and help the neighboring Gulf States Group with emergency power.

During the 10-year period from 1980 to 1989, summer and winter peak is projected to increase at an average rate of 5.5 percent per year (see Table 8A.8). Annual energy requirements are forecasted to increase at a rate of 5.4 percent. The annual load factor is expected to vary only slightly from 57.0 percent to 57.3 percent during the decade.

Table 8A.9 shows that the Middle South Utilities Group is and will continue to be heavily dependent upon natural gas and oil-fired capacity. Gas and oil-fired generation is expected to constitute 78.9 percent of total net capability during the 1980 summer peak. This percentage is projected to decrease to 55.1 percent in 1985 and 46.8 percent in 1989. Assuming purchases of 590 MW during the 1989 summer peak, the Region's total capability would have an average plant factor of 49.1 percent based upon a net capability of 21980 MW and energy requirements of 94528 GWh. If half of the 10015 MW of gas and oil-fired capacity were unavailable, the remaining units would have to operate at an average plant factor of 65.9 percent.

Table 8A.3

HISTORICAL LOAD GROWTH
Middle South Utilities Group (Region 8)

	- D e m a n d -				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1977	11,480	-	7,980	-	53,954	-	53.7
1978	11,322	-1.38	8,591	7.66	57,453	6.49	57.9
1979	11,433	0.98	8,613	0.26	59,482	3.53	59.4

Table 8A.4.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Middle South Utilities Group (Region 8)

	<u>1 9 7 7</u>			<u>1 9 7 8</u>			<u>1 9 7 9</u>		
	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>
1. Planned Capability	12492	12466	12485	12463	12462	12462	12479	12478	12478
2. Peak Demand	10239	10632	11480	10945	11122	11322	10893	11353	11433
3. Planned Reserves (1-2)	2253	1834	1005	1518	1340	1140	1586	1125	1045
4. Planned Reserves (%) (3/2)x100	22.0	17.2	8.8	13.9	12.0	10.1	14.6	9.9	9.1
5. Net Transactions (Imports-Exports)	1493	1523	1927	3263	3032	2428	2728	4021	2051
6. Total Capability (1+5)	13985	13989	14412	15726	15494	14890	15207	16499	14529
7. Total Reserves (6-2)	3746	3357	2932	4731	4372	3568	4314	5146	3096
8. Total Reserves (%) (7/2)x100	36.6	31.6	25.5	43.7	39.3	31.5	39.6	45.3	27.1
9. Scheduled Maintenance	866	0	260	12	0	0	0	0	0
10. Capability after Maintenance (6-9)	13119	13989	14152	15714	15494	14890	15207	16499	14529
11. Reserves after Maintenance (10-2)	2880	3357	2672	4769	4372	3568	4314	5146	3096
12. Reserves after Maintenance (%) (11/2)x100	28.1	31.6	23.3	43.6	39.3	31.5	39.6	45.3	27.1
13. Inoperable Capability	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	13119	13989	14152	15714	15494	14890	15207	16499	14529
15. Available Reserves (14-2)	2880	3357	2672	4769	4372	3568	4314	5146	3096
16. Available Reserves (%) (15/2)x100	28.1	31.6	23.3	43.6	39.3	31.5	39.6	45.3	27.1
17. Forced Outages	1112	839	380	2293	2380	1418	2394	1457	1056
18. Actual Capability after Forced Outages (14-17)	12007	13150	13772	13421	13114	13472	12813	15042	13473
19. Actual Reserves (18-2)	1768	2518	2292	2476	1992	2150	1920	3689	2040
20. Actual Reserves (%) (19/2)x100	17.3	23.7	20.0	22.6	17.9	19.0	17.6	32.5	17.8

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Table 8A.4.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Middle South Utilities Group (Region 8)

	<u>1977/78</u>			<u>1978/79</u>			<u>1979/80</u>		
	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>
1. Planned Capability	12471	12470	12475	12483	12482	12482	12492	12491	12491
2. Peak Demand	7552	7980	7802	8166	8591	8491	8613	8581	8566
3. Planned Reserves (1-2)	4919	4490	4673	4317	3891	3991	3879	3910	3925
4. Planned Reserves (%) (3/2)x100	65.1	56.3	59.9	52.9	45.3	47.0	45.0	45.6	45.8
5. Net Transactions (Imports-Exports)	1200	903	131	2176	276	1276	1622	3080	1772
6. Total Capability (1+5)	13671	13373	12606	14659	12758	13758	14114	15571	14263
7. Total Reserves (6-2)	6119	5393	4804	6493	4167	5267	5501	6990	5697
8. Total Reserves (%) (7/2)x100	81.0	67.6	61.6	79.5	48.5	62.0	63.9	81.5	66.5
9. Scheduled Maintenance	2479	1298	1272	1622	645	1413	1023	976	932
10. Capability after Maintenance (6-9)	11192	12075	11334	13037	12113	12345	13091	14595	13331
11. Reserves after Maintenance (10-2)	3640	4095	3532	4871	3522	3854	4478	6014	4765
12. Reserves after Maintenance (%) (11/2)x100	48.2	51.3	45.3	59.6	41.0	45.4	52.0	70.1	55.6
13. Inoperable Capability	30	29	29	30	29	29	30	29	0
14. Available Capability (10-13)	11162	12046	11305	13007	12084	12316	13061	14566	13331
15. Available Reserves (14-2)	3610	4066	3503	4841	3493	3825	4448	5985	4765
16. Available Reserves (%) (15/2)x100	47.8	51.0	44.9	59.3	40.7	45.0	51.6	69.7	55.6
17. Forced Outages	1133	1880	1140	2498	1517	2064	1410	2596	1378
18. Actual Capability after Forced Outages (14-17)	10029	10166	10165	10509	10567	10252	11651	11970	11953
19. Actual Reserves (18-2)	2477	2186	2363	2343	1976	1761	3038	3389	3387
20. Actual Reserves (%) (19/2)x100	32.8	27.4	30.3	28.7	23.0	20.7	35.3	39.5	39.5

XI.9.10

Table 8A.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Middle South Utilities Group (Region 8)

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability	13508	13405
2. Peak Demand	11711	8705
3. Planned Reserves (1-2)	1797	4700
4. Planned Reserves (%) (3/2)x100	15.3	54.0
5. Net Transactions (Imports-Exports)	1173	627
6. Total Capability (1+5)	14681	14032
7. Total Reserves (6-2)	2970	5327
8. Total Reserves (%) (7/2)x100	25.4	61.2
9. Scheduled Maintenance	0	1856
10. Capability after Maintenance (6-9)	14681	12176
11. Reserves after Maintenance (10-2)	2970	3471
12. Reserves after Maintenance (%) (11/2)x100	25.4	39.9
13. Inoperable Capability	0	0
14. Available Capability (10-13)	14681	12176
15. Available Reserves (14-2)	2970	3471
16. Available Reserves (%) (15/2)x100	25.4	39.9
17. Forced Outages	1571	1856
18. Actual Capability after Forced Outages (14-17)	13110	10320
19. Actual Reserves (18-2)	1399	1615
20. Actual Reserves (%) (19/2)x100	11.9	18.6

1/ No Delays Anticipated since Submission of 1980 ERA-411.

2/ Estimated by ERA staff based on historical forced outage amounts.

Table 8A.6

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Middle South Utilities Group (Region 8)

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	14240	14137	16422	16319	17064	16961	16940	16862
2. Peak Demand	12300	9145	12935	9619	13836	10290	14613	10869
3. Planned Reserves (1-2)	1940	4992	3487	6700	3228	6671	2327	5993
4. Planned Reserves (%) (3/2)x100	15.8	54.6	27.0	69.7	23.3	64.8	15.9	55.1
5. Net Transactions (Imports-Exports)	1002	578	1027	603	1028	605	727	605
6. Total Capability (1+5)	15242	14715	17449	16922	18092	17566	17667	17467
7. Total Reserves (6-2)	2942	5570	4514	7303	4256	7276	3054	6598
8. Total Reserves (%) (7/2)x100	23.9	60.9	34.9	75.9	30.8	70.7	20.9	60.7
9. Scheduled Maintenance	0	1922	0	2250	0	2303	0	2288
10. Capability after Maintenance (6-9)	15242	12793	17449	14672	18092	15263	17667	15179
11. Reserves after Maintenance (10-2)	2942	3648	4514	5053	4256	4973	3054	4310
12. Reserves after Maintenance (%) (11/2)x100	23.9	39.9	34.9	52.5	30.8	48.3	20.9	39.7
13. Inoperable Capability	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	15242	12793	17449	14672	18092	15263	17667	15179
15. Available Reserves (14-2)	2942	3648	4514	5053	4256	4973	3054	4310
16. Available Reserves (%) (15/2)x100	23.9	39.9	34.9	52.5	30.8	48.3	20.9	39.7
17. Forced Outages	1650	1950	1730	2050	1855	2190	1960	2320
18. Actual Capability after Forced Outages (14-17)	13592	10843	15719	12622	16237	13073	15707	12859
19. Actual Reserves (18-2)	1292	1698	2784	3003	2401	2783	1094	1990
20. Actual Reserves (%) (19/2)x100	10.5	18.6	21.5	31.2	17.4	27.0	7.5	18.3

XI.8.12

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	1110	0	0	0	0	0
22. Actual Capability (18-21)	13592	10843	14609	12622	16237	13073	15707	12859
23. Actual Reserves with Nuclear Delays (22-2)	1292	1698	1674	3003	2401	2783	1094	1990
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	10.5	18.6	12.9	31.2	17.4	27.0	7.5	18.3

Coal Unit Delays Assumed Possible by ERA

25. Possible Coal Delays	0	0	0	0	725	0	0	0
26. Actual Capability w/Nuclear & Coal Delays (22-25)	13592	10843	14609	12622	15512	13073	15707	12859
27. Actual Reserves w/Nuclear & Coal Delays (26-2)	1292	1698	1674	3003	1676	2783	1094	1990
28. Actual Reserves w/Nuclear & Coal Delays (%) (27/2)x100	10.5	18.6	12.9	31.2	12.1	27.0	7.5	18.3

1/ Estimated by ERA staff based on historical forced outage amounts.

Table 8A.7

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Middle South Utilities Group (Region 8)

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	18667	18604	18508	18508	19428	19428	20222	20222	21390	21390
2. Peak Demand	15345	11417	16129	12002	17034	12677	17997	13397	18902	14077
3. Planned Reserves (1-2)	3322	7187	2379	6506	2394	6751	2225	6825	2488	7313
4. Planned Reserves (%) (3/2)x100	21.6	62.9	14.7	54.2	14.1	53.3	12.4	50.9	13.2	51.9
5. Net Transactions (Imports-Exports)	730	608	686	564	704	582	705	583	590	468
6. Total Capability (1+5)	19397	19212	19194	19072	20132	20010	20927	20805	21980	21858
7. Total Reserves (6-2)	4052	7795	3065	7070	3098	7333	2930	7408	3078	7781
8. Total Reserves (%) (7/2)x100	26.4	68.3	19.0	58.9	18.2	57.8	16.3	55.3	16.3	55.3
9. Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-
10. Capability after Maintenance (6-9)	19397	19212	19194	19072	20132	20010	20927	20805	21980	21858
11. Reserves after Maintenance (10-2)	4052	7795	3065	7070	3098	7333	2930	7408	3078	7781
12. Reserves after Maintenance (%) (11/2)x100	26.4	68.3	19.0	58.9	18.2	57.8	16.3	55.3	16.3	55.3
13. Inoperable Capability	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	19397	19212	19194	19072	20132	20010	20927	20805	21980	21858
15. Available Reserves (14-2)	4052	7795	3065	7070	3098	7333	2930	7408	3078	7781
16. Available Reserves (%) (15/2)x100	26.4	68.3	19.0	58.9	18.2	57.8	16.3	55.3	16.3	55.3
17. Forced Outages	-	-	-	-	-	-	-	-	-	-
18. Actual Capability after Forced Outages (14-17)	19397	19212	19194	19072	20132	20010	20927	20805	21980	21858
19. Actual Reserves (18-2)	4052	7795	3065	7070	3098	7333	2930	7408	3078	7781
20. Actual Reserves (%) (19/2)x100	26.4	68.3	19.0	58.9	18.2	57.8	16.3	55.3	16.3	55.3

XI.8.13

1/ No Nuclear or Coal Unit Delays are anticipated in this time frame.

Table 8A.8

FUTURE LOAD GROWTH
Middle South Utilities Group (Region 8)

	- D e m a n d -				Energy Requirements		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	11,711	-	8,705	-	58,906	-	57.3
1981	12,300	5.0	9,145	5.1	61,790	4.9	57.3
1982	12,935	5.2	9,619	5.2	64,897	5.0	57.3
1983	13,836	7.0	10,290	7.0	69,404	6.9	57.3
1984	14,613	5.6	10,869	5.6	73,269	5.6	57.1
1985	15,345	5.0	11,417	5.0	76,889	4.9	57.2
1986	16,129	5.1	12,002	5.1	80,780	5.1	57.2
1987	17,034	5.6	12,677	5.6	85,274	5.6	57.1
1988	17,997	5.7	13,397	5.7	90,054	5.6	57.0
1989	18,902	<u>5.0</u>	14,077	<u>5.1</u>	94,528	<u>5.0</u>	57.1
1980-89		5.5		5.5		5.4	

Table 8A.9

GENERATION MIX BY FUEL TYPE
Middle South Utilities Group (Region 8)

Type Fuel	Summer 1980		Summer 1985		Summer 1989	
	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)
Nuclear	1,748	13.0	5,108	27.4	5,108	23.9
Coal	1,022	7.6	3,198	17.1	6,198	29.0
Gas	8,785	65.0	8,408	45.0	8,131	38.0
Oil	1,884	13.9	1,884	10.1	1,884	8.8
Hydro	<u>69</u>	<u>0.5</u>	<u>69</u>	<u>0.4</u>	<u>69</u>	<u>0.3</u>
Total	13,508	100.0	18,667	100.0	21,390	100.0

GULF STATES GROUP (REGION 10)Historical Perspective

The Gulf States Region encompasses portions of Louisiana and Texas with Gulf States Utilities Company owning about 65 percent of the total capability of the region. Historically, all of the Gulf States Region's generation has been obtained from either oil or gas. However, by 1989 the region is projecting the installation of coal-fired and nuclear capacity which will constitute 49.5 percent of its total installed capability.

The annual peak demand (which occurs in the summer) and annual energy requirements for the Gulf States Region has shown a steady decrease in growth rates from 1950 to 1976. This data is shown in the following table.

Table 8B.1
Historical Load Growth Rates
Gulf States Group

<u>Period</u>	<u>Compound Annual Growth Rate</u>	
	<u>Peak Demand</u>	<u>Annual Energy</u>
	(%)	(%)
1950-60	12.2	11.4
1960-70	10.5	10.8
1970-76	6.0	6.2

Table 8B.5 shows the actual summer and winter peak demands and the annual net energy for load for the years 1977 through 1979. The annual growth rates for demand and energy for these periods are also tabulated. This shows very little growth from 1978 to 1979.

From 1977 to 1979, Gulf States had adequate total generating reserves at the time of the peak to satisfy the SPP criteria (see Region 8 Historical Perspective for Criteria). However, actual reserves during the summer were below the 6 percent SPP criteria during the 1977-79 summer peaks (see Table 8B.5). During February 1979 the actual reserves fell well below this figure due to power sales and high unit outages. The low reserves available during the summer were due to generating outages other than normal scheduled maintenance. These outages have ranged from a low of 15.4 percent to a high of 22.7 percent of Gulf States' own generating resources during the months when the peak demand occurs. The large amount of

unavailable capacity in the region is mainly due to the use of oil-fired units that were originally designed to burn natural gas. Unreliable supplies of natural gas has necessitated the use of oil. These units are the Willow Glen Units Nos. 3 and 4 (1,000 MW total), and Nelson Unit No. 4 (500 MW).

The following table shows the actual December 1979 generating capability by fuel type and the 1979 actual energy generation.

Table 8B.2
1979 Net Dependable Capability and Generation by Fuel Type
Gulf States Group

<u>Fuel Type</u>	<u>Net Dependable Capability</u>		<u>Generation</u>	
	<u>(MW)</u>	<u>(% of Total)</u>	<u>(GWh)</u>	<u>(% of Total)</u>
Coal	0	0	0	0
Oil	2,050	25.3	4,028.1	11.5
Natural Gas	6,043	74.7	30,974.9	88.5
Nuclear	0	0	0	0
Hydro	0	0	0	0
Other	0	0	0	0
Total	8,093	100.0	35,003.0	100.0

As depicted in the above table, Gulf States is heavily dependent upon natural gas for the generation of electric power. Relief in this situation will occur beginning in 1980 when its first coal-fired unit (Big Cajun No. 2, Unit 1 540 MW) goes into service. This will start a steady increase in the amount of coal-fired capacity in the region with a total of 6,970 MW projected to be added by 1989. An additional 846 MW of nuclear capacity (River Bend No. 1) is projected for 1984.

Historically, the Gulf States Region has been a net purchaser of capacity and energy during the 1977-79 summer peak periods. This power has been transmitted via 500 kv interconnections with the Middle South Systems (Louisiana Power & Light Company, the Mississippi Power & Light Company, and Arkansas Power & Light Company). Included in these purchases is a portion of the SCEC--TVA diversity exchange. Gulf States was a net seller of energy in 1977 (222.2 GWh), a slight net purchaser in 1978 (40.1 GWh), and a large net purchaser in 1979 (3,600 GWh). The 1979 purchases represented 9.3 percent of its net energy for load.

Current Perspective

The Gulf States Group is projecting two 540 MW coal-fired generating units between summer 1980 and winter 1980-81 (Big Cajun No. 2, units 1 and 2). Unit No. 1 will be in by the 1980 summer peak and Unit No. 2 will be in by the 1980-81 winter peak. At present, these target dates are still considered realistic by the owner, Cajun Electric Power Cooperative. This office sees no reason at this time that these two units should not be placed in service as scheduled.

The winter peak for the region is projected to be about 24 percent lower than the summer peak. With expected unit additions the actual reserves for the 1980-81 winter peak would be 16.0 percent (see Table 8B.7). This appears adequate under all but abnormal circumstances.

A total reserve of 22.0 percent is projected for this summer, which is well above the SPP criteria. Since no maintenance was scheduled and Gulf States projects no inoperable capability the available reserve was also 22.0 percent. The actual reserve (which includes ERA's estimate of possible forced outages) is 1.6 percent. The forced outages for the region were estimated based on a historical average of 20.4 percent for the summer peak and 26.5 percent for the winter peak during the 1977-79 period. The figure includes both full forced outages and inoperable capability (partial forced outages would be in this category). Historically, Region 10 has had a considerable amount of capacity out for forced outages, or inoperable for other reasons, at the time of the summer peak. However, in ERA-411, Gulf States predicts no inoperable capability during the summer peak period. Thus, the historical 20.4 percent outage figure has been applied entirely to forced outages.

The Gulf States Group would appear to be able to supply all of its load requirements during the 1980 summer peak even if historical forced outages do occur again. If necessary, emergency power would probably be available over strong 500-kV ties with the Middle South Utilities Group (Region 8). Gulf States presently has three 500-kV interconnections with Middle South Utilities. These three lines each have a maximum capacity rating of 1,000 MW. A load flow diagram supplied in the 1980 ERA-411 predicts an import of 448 MW by the Gulf States area over these 500-kV lines during the 1980 summer peak period. The ability to transfer additional capacity between the two regions would appear very good. However, under no circumstances should it be assumed that since the three lines have ratings of 1,000 MW each that corresponding large amounts of additional power can be transferred. The transfer of capacity is only partly dependent on tie line capacity. In most cases the

limitation of the lower voltage transmission network of both systems and the location of generating sources dictate how such power can safely be transferred.

The Gulf States Group is projecting a 5.9 percent growth in the 1981-1984 period. Capacity additions during this period will be 2,150 MW of coal-fired capacity, 846 MW of nuclear capacity, and 180 MW of combustion turbines.

Total reserves for this region (see Table 8E.8) range from 18.3 percent to 24.6 percent during the summer and appear adequate. Reserves after maintenance are also projected to range from 18.3 to 24.6 percent. Actual reserves (which include estimated forced outages and inoperable capability) are expected to range between -2.1 percent and 4.2 percent. The region would appear to be capacity deficient during the 1981 summer peak period if forced outages, as they have previously encountered, occur again.

If projected nuclear delays and possible coal unit delays are also considered, 1,070 MW and 856 MW would be unavailable resulting in actual reserves of -8.1 percent in 1982 and -7.1 percent in 1984, which would appear inadequate without any help from neighboring systems. The actual reserves during the 1983 and 1984 winter peak period could be below the SPP criteria. However, neighboring systems are also summer peaking areas and emergency transfers would be highly probable during the winter.

The Gulf States Group could very possibly have trouble meeting its peak load requirements in the 1981-1984 period. Assuming forced outages and unit delays (which this office feels are very possible) the Region would have to purchase additional capacity of 175 MW in 1981, 703 MW in 1982, and 685 MW in 1984 during the peak period just to meet projected load with no reserves.

The emergency power needed by Gulf States could possibly come from the Oklahoma Group, but more likely would come from the Middle South Utilities Group via its existing 500-kV ties. In addition, there is a proposed 345-kV tie with the Oklahoma Group in 1981 to relieve overloads, a 500-kV tie with Middle South in 1984, and a 230-kV tie in 1986 with Louisiana Power & Light Company for the purpose of increasing interchange capability. The following table depicts the projected capacity deficiency in the Gulf States Group and the possible excess capacity in the Middle South Group assuming forced outages and generating unit delays.

Table 8B.3
Potential Emergency Capacity Sources
Gulf States Group

<u>Year</u>	<u>Gulf States Capacity Deficiency (MW)</u>	<u>Middle South Excess Capacity (MW)</u>
1981	175	1,292
1982	703	1,674
1984	685	1,094

The Gulf States Group needs to meet their projected generating unit schedules (even a delay of less than a year may be disastrous), since improved availability is needed from their oil burning units to assure that peak demand and energy requirements are met.

The long term reserve situation for the Region is not as dismal as the near term. A total of 3,740 MW of coal-fired capacity is projected in the 1985-1989 time period to supply a peak demand increase of 2,413 MW during the same time frame. With this differential in capacity, actual summer reserves would range from 21.0 percent to 26.4 percent (see Table 8B.9). A possible nuclear delay of 846 MW in 1985 would only decrease the reserve to 16.8 percent, which appears adequate.

These reserves do not reflect any scheduled maintenance or forced outages. Assuming that there would not be any maintenance scheduled during the summer peak period and applying the same 20.4 percent for forced outages as assumed in the Current Perspective the reserves would be as follow:

Table 8B.4
Estimated Actual Summer Reserves
Gulf States Group

<u>Year</u>	<u>Estimated Actual Summer Reserves</u>
1985	-3.6%
1986	5.9%
1987	2.4%
1988	3.9%
1989	0.6%

It would appear that Gulf States may still need some emergency capacity assistance, but with the previously mentioned 500-kV tie with Middle South Utilities in 1984 and also a proposed 230-kV tie with the region planned for 1986, sufficient transmission paths should be available to facilitate the transfer of any needed power in the Gulf States Group.

Future Perspective

The growth of summer peak demand, winter peak demand and annual energy requirements are all projected to average 5.7 percent during the 1980-89 report period. Table 8B.6 provides estimates for the three items and shows annual growth in percent. The annual load factor is predicted to be 62.2 percent in 1980 and 63.4 percent in 1981, declining to 62.4 percent in 1989.

Projected annual energy requirements can be met throughout the report period, assuming that emergency capacity can be purchased when and if needed and a sufficient supply of natural gas and oil for boiler use can be maintained. During the summer of 1989 the Gulf States Group is projecting a capacity mix of 5.6 percent nuclear, 41.9 percent coal, and 52.5 percent gas and oil (see Table 8B.11) for a total planned summer capability of 15,211 MW. The total capability (15,415 MW which includes 204 MW of net purchases) would have an average plant factor of 51.6 percent in 1989. If 50 percent of the gas and oil capability were inoperable, the remaining capability would be required to operate at an average plant factor of 69.6 percent to serve the annual energy requirement of 69,639 GWh in 1989.

Table 8B.5
Gulf States Group (Region 10)
(Historical Load Growth)

	- D e m a n d -				Annual Energy Requireemtns		Annual Load
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	Factor (%)
1977	6,182	-	4,987	-	34,690	-	64.1
1978	6,769	9.50	5,209	4.45	37,564	8.28	63.3
1979	6,871	1.51	5,345	2.61	38,663	2.93	64.2

Table 8B.6.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Gulf States Group

	S			U			M			E			R		
	9	7	7	9	7	7	9	7	8	9	7	7	9	7	9
	Jun.	Jul.	Aug.	Jun.	Jul.	Aug.	Jun.	Jul.	Aug.	Jun.	Jul.	Aug.	Jun.	Jul.	Aug.
1. Planned Capability	7666	7666	7666	7680	7680	7680	7665	7665	7665						
2. Peak Demand	5912	6182	6011	6628	6636	6769	6575	6871	6796						
3. Planned Reserves (1-2)	1754	1484	1655	1052	1044	911	1090	794	869						
4. Planned Reserves (%) (3/2)x100	29.7	24.0	27.5	15.9	15.7	13.5	16.6	11.6	12.8						
5. Net Transactions (Imports-Exports)	145	377	22	236	57	1351	1011	711	1087						
6. Total Capability (1+5)	7811	8043	7588	7916	7737	9031	8676	8376	8752						
7. Total Reserves (6-2)	1899	1861	1577	1288	1101	2262	2101	1505	1956						
8. Total Reserves (%) (7/2)x100	32.1	30.1	27.9	19.4	16.6	33.4	32.0	21.9	28.8						
9. Scheduled Maintenance	10	0	0	0	0	265	12	0	0						
10. Capability after Maintenance (6-9)	7801	8043	7588	7916	7737	8766	8664	8376	8752						
11. Reserves after Maintenance (10-2)	1889	1861	1577	1288	1101	1997	2089	1505	1956						
12. Reserves after Maintenance (%) (11/2)x100	32.0	30.1	27.9	19.4	16.6	29.5	31.8	21.9	28.8						
13. Inoperable Capability	876	569	565	294	649	1222	918	548	453						
14. Available Capability (10-13)	6925	7474	7023	7622	7088	7544	7746	7828	8299						
15. Available Reserves (14-2)	1013	1292	1012	994	452	775	1171	957	1503						
16. Available Reserves (%) (15/2)x100	17.1	20.9	15.8	15.0	6.8	11.4	17.8	13.9	22.1						
17. Forced Outages	774	1090	0	665	100	522	635	635	1280						
18. Actual Capability after Forced Outages (14-17)	6151	6384	7023	6957	6988	7022	7111	7193	7019						
19. Actual Reserves (18-2)	239	202	1012	329	352	253	536	322	223						
20. Actual Reserves (%) (19/2)x100	4.0	3.3	15.8	5.0	5.3	3.7	8.2	4.7	3.3						

XI.8.22

Table 8B.6.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Gulf States Group

	- W I N T E R -								
	1 9 7 7 / 7 8			1 9 7 8 / 7 9			1 9 7 9 / 8 0		
	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.
1. Planned Capability	7670	7666	7657	7679	7679	7679	8145	8145	8135
2. Peak Demand	4413	4987	4722	4876	5209	5128	5338	5277	5345
3. Planned Reserves (1-2)	3257	2679	2935	2803	2470	2551	2807	2868	2790
4. Planned Reserves (%) (3/2)x100	73.8	53.7	62.2	57.5	47.4	49.7	52.6	54.3	52.2
5. Net Transactions (Imports-Exports)	-21	316	344	-278	511	-376	681	346	674
6. Total Capability (1+5)	7649	7982	8001	7401	8190	7303	8826	8491	8809
7. Total Reserves (6-2)	3236	2995	3279	2525	2981	2175	3888	3214	3464
8. Total Reserves (%) (7/2)x100	73.3	60.1	69.4	51.8	57.2	42.4	65.3	60.1	64.8
9. Scheduled Maintenance	825	911	911	1182	1129	629	1269	1162	1162
10. Capability after Maintenance (6-9)	6824	7071	7090	6219	7061	6674	7557	7329	7647
11. Reserves after Maintenance (10-2)	2411	2084	2368	1343	1852	1546	2219	2052	2302
12. Reserves after Maintenance (%) (11/2)x100	54.6	41.8	50.1	27.5	35.6	30.1	41.6	38.9	43.1
13. Inoperable Capability	521	779	1182	935	733	1022	459	428	248
14. Available Capability (10-13)	6303	6292	5908	5284	6328	5652	7098	6901	7399
15. Available Reserves (14-2)	1890	1305	1186	408	1119	524	1760	1624	2054
16. Available Reserves (%) (15/2)x100	42.8	26.2	25.1	8.4	21.5	10.2	33.0	30.8	38.4
17. Forced Outages	1072	550	550	0	500	500	0	995	1450
18. Actual Capability after Forced Outages (14-17)	5231	5742	5358	5284	5828	5152	7098	5906	5949
19. Actual Reserves (18-2)	818	755	636	408	619	24	1760	629	604
20. Actual Reserves (%) (19/2)x100	18.5	15.1	13.5	8.4	11.9	0.5	33.0	11.9	11.3

Table 88.7

Current Capability (MW) and Reserves (MW and Percent)
GULF STATES GROUP

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	8405	8945
2. Peak Demand	7694	5865
3. Planned Reserves (1-2)	711	3080
4. Planned Reserves (%) (3/2)x100	9.2	52.5
5. Net Transactions (Imports-Exports)	981	603
6. Total Capability (1+5)	9386	9548
7. Total Reserves (6-2)	1692	3683
8. Total Reserves (%) (7/2)x100	22.0	62.8
9. Scheduled Maintenance	0	1191
10. Capability after Maintenance (6-9)	9386	8357
11. Reserves after Maintenance (10-2)	1692	2492
12. Reserves after Maintenance (%) (11/2)x100	22.0	42.5
13. Inoperable Capability	0	0
14. Available Capability (10-13)	9386	8357
15. Available Reserves (14-2)	1692	2492
16. Available Reserves (%) (15/2)x100	22.0	42.5
17. Forced Outages <u>2/</u>	1570	1554
18. Actual Capability after Forced Outages (14-17)	7816	6803
19. Actual Reserves (18-2)	122	938
20. Actual Reserves (%) (19/2)x100	1.6	16.0

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ Estimated by ERA staff based on historical forced outage amounts.

Table 8B.8

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Gulf States Group

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	9035	9300	10195	10735	10735	10735	11581	12121
2. Peak Demand	8173	6212	8657	6584	9173	6972	9710	7411
3. Planned Reserves (1-2)	862	3088	1538	4151	1562	3763	1871	4710
4. Planned Reserves (%) (3/2)x100	10.5	49.7	17.8	63.0	17.0	54.0	19.3	63.6
5. Net Transactions (Imports-Exports)	630	223	595	398	596	245	271	170
6. Total Capability (1+5)	9665	9523	10790	11133	11331	10980	11852	12291
7. Total Reserves (6-2)	1492	3311	2133	4549	2158	4008	2142	4880
8. Total Reserves (%) (7/2)x100	18.3	53.3	24.6	69.1	23.5	57.5	22.1	65.8
9. Scheduled Maintenance	0	899	0	810	0	1846	0	1764
10. Capability after Maintenance (6-9)	9665	8624	10790	10323	11331	9134	11852	10527
11. Reserves after Maintenance (10-2)	1492	2412	2133	3739	2158	2162	2142	3116
12. Reserves after Maintenance (%) (11/2)x100	18.3	38.3	24.6	56.8	23.5	31.0	22.1	42.0
13. Inoperable Capability	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	9665	8624	10790	10323	11331	9134	11852	10527
15. Available Reserves (14-2)	1492	2412	2133	3739	2158	2162	2142	3116
16. Available Reserves (%) (15/2)x100	18.3	38.3	24.6	56.8	23.5	31.0	22.1	42.0
17. Forced Outages	1667	1646	1766	1745	1871	1848	1981	1964
18. Actual Capability after Forced Outages (14-17)	7998	6978	9024	8578	9460	7286	9871	8563
19. Actual Reserves (18-2)	-175	766	367	1994	287	314	161	1152
20. Actual Reserves (%) (19/2)x100	-2.1	12.3	4.2	30.3	3.1	4.5	1.7	15.5

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	0	0	846	846
22. Actual Capability (18-21)	7998	6978	9024	8578	9460	7286	9025	7717
23. Actual Reserves with Nuclear Delays (22-2)	-175	766	367	1994	287	314	-685	306
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	-2.1	12.3	4.2	30.3	3.1	4.5	-7.1	4.1

Coal Unit Delays Assumed Possible by ERA

25. Possible Coal Delays	0	265	1070	805	0	0	0	0
26. Actual Capability w/Nuclear & Coal Delays (22-25)	7998	6713	7954	7773	9460	7286	9025	7717
27. Actual Reserves w/Nuclear & Coal Delays (26-2)	-175	501	-703	1189	287	314	-685	306
28. Actual Reserves w/Nuclear & Coal Delays (%) (27/2)x100	-2.1	8.1	-8.1	18.1	3.1	4.5	-7.1	4.1

Table 8B.9

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Gulf States Group

	<u>1985</u>		<u>1986</u>		<u>1987</u>		<u>1988</u>		<u>1989</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	12661	13201	13521	13871	13871	14676	14811	15211	15211	15811
2. Peak Demand	10322	7821	10893	8237	11474	8677	12087	9142	12735	9634
3. Planned Reserves (1-2)	2339	5380	2628	5634	2397	5999	2724	6069	2476	6177
4. Planned Reserves (%) (3/2)x100	22.7	68.8	24.1	68.4	20.9	69.1	22.5	66.4	19.4	64.1
5. Net Transactions (Imports-Exports)	242	160	232	151	223	141	213	132	204	123
6. Total Capability (1+5)	12903	13361	13753	14022	14094	14817	15024	15343	15415	15934
7. Total Reserves (6-2)	2581	5540	2860	5785	2620	6140	2937	6201	2680	6300
8. Total Reserves (%) (7/2)x100	25.0	70.8	26.3	70.2	22.8	70.8	24.3	67.8	21.0	65.4
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	12903	13361	13753	14022	14094	14817	15024	15343	15415	15934
11. Reserves after Maintenance (10-2)	2581	5540	2860	5785	2620	6140	2937	6201	2680	6300
12. Reserves after Maintenance (%) (11/2)x100	25.0	70.8	26.3	70.2	22.8	70.8	24.3	67.8	21.0	65.4
13. Inoperable Capability 1/	0	0	0	0	0	0	0	0	0	0
14. Available Capability (10-13)	12903	13361	13853	14022	14094	14817	15024	15343	15415	15934
15. Available Reserves (14-2)	2581	5540	2860	5785	2620	6140	2937	6201	2680	6300
16. Available Reserves (%) (15/2)x100	25.0	70.8	26.3	70.2	22.8	70.8	24.3	67.8	21.0	65.4
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	12903	13361	13853	14022	14094	14817	15024	15343	15415	15934
19. Actual Reserves (18-2)	2581	5540	2860	5785	2620	6140	2937	6201	2680	6300
20. Actual Reserves (%) (19/2)x100	25.0	70.8	26.3	70.2	22.8	70.8	24.3	67.8	21.0	65.4

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	846	846	0	0	0	0	0	0	0	0
22. Actual Capability (18-21)	12057	12515	13853	14022	14094	14817	15024	15343	15415	15934
23. Actual Reserves with Nuclear Delays (22-2)	1735	4694	2860	5785	2620	6140	2937	6201	2	6300
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	16.8	60.0	26.3	70.2	22.8	70.8	24.3	67.8	21.0	65.4

1/ Information not available for this period.

Table 8B.10

FUTURE LOAD GROWTH
Gulf States Group

	- D e m a n d -				Energy Requirements		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	7,712	-	5,847	-	42,125	-	62.2
1981	8,173	6.0	6,192	5.9	45,359	7.7	63.4
1982	8,657	5.9	6,563	6.0	47,975	5.8	63.3
1983	9,172	5.9	6,950	5.9	50,764	5.8	63.2
1984	9,710	5.9	7,387	6.3	53,768	5.9	63.0
1985	10,322	6.3	7,796	5.5	56,865	5.8	62.9
1986	10,893	5.5	8,211	5.3	59,907	5.3	62.8
1987	11,475	5.3	8,649	5.3	62,976	5.1	62.6
1988	12,088	5.3	9,112	5.4	66,327	5.3	62.5
1989	12,736	<u>5.4</u>	9,603	<u>5.4</u>	69,639	<u>5.0</u>	62.4
1980-89		5.7		5.7		5.7	

Table 8B.11

Capacity Mix (MW) By Fuel Type
GULF STATES GROUP

Type Fuel	Summer 1980		Summer 1985		Summer 1989	
	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)
Nuclear	0	0.0	846	6.7	846	5.6
Coal	540	6.4	3,770	29.8	6,370	41.9
Gas	5,815	69.2	5,995	47.3	5,995	39.4
Oil	2,050	24.4	2,050	16.2	2,000	13.1
Hydro	<u>0</u>	<u>-</u>	<u>0</u>	<u>-</u>	<u>0</u>	<u>-</u>
Total	8,405	100.0	12,661	100.0	15,211	100.0

MISSOURI-KANSAS GROUP (REGION 21)Historical Perspective

Although the historical growth rate for the Missouri-Kansas Group (MOKAN) has been slightly less than the other Electric Regions within SPP, it has also been experiencing growth rate reductions in both peak demand and annual energy requirements. The following table illustrates this reduction in electric usage during the period 1950 through 1976:

Table 8C.1

Historical Load Growth
Missouri-Kansas Group

<u>Period</u>	<u>Compound Annual Growth Rate</u>	
	<u>Peak Demand</u>	<u>Energy</u>
	(%)	(%)
1950-60	10.4	8.7
1960-70	8.1	7.7
1970-76	5.5	5.2

Table 8C.3 shows actual summer and winter peak loads, annual energy requirements, annual growth rates and annual load factors for 1977, 1978 and 1979 for the MOKAN Region. The MOKAN Region experienced a reduction in load of 4.2 percent between the summer of 1978 and the summer of 1979 with corresponding reduction in energy of one percent for the 1978-1979 period. Systems in the region attribute about 70 percent of this reduction to cooler than normal temperatures during the summer of 1979 and the remainder to customer conservation efforts.

Due to this reduction in load growth, the MOKAN area has been reducing its load estimate annually for the past several years. For the period 1980 through 1989 MOKAN is estimating an average compound growth rate of 4.4 percent. This compares to projected growth rates of 4.5 percent in 1979 and approximately 6 percent in 1978.

The MOKAN Region is the only region in SPP which obtains more than one-half of its annual generation from coal-fired generating units. The following table gives a breakdown of generating capacity by fuel type and generation in the Region as of the end

of 1979. The information was obtained from data reported to the Energy Information Administration via their Form 4.

Table 8.C2

Installed Capacity and Generation by Fuel Type

Missouri-Kansas Group

<u>Fuel Type</u>	<u>Installed Capacity</u>		<u>Generation</u>	
	(MW)	(% of Total)	(GWh)	(% of Total)
Nuclear	0	0.0	0	0.0
Coal	6,900	60.1	21,912	65.0
Natural Gas	3,442	30.0	10,143	30.1
Oil	1,128	9.8	1,582	4.7
Hydro	16	0.1	56	0.2
Other	0	0.0	0	0.0
Total	11,486	100.0	33,693	100.0

During the 1980 summer peak period, the generating capacity mix by fuel type will be approximately 69.7 percent coal, 9.3 percent oil, 20.9 percent natural gas, and 0.1 percent hydroelectric. The first nuclear unit in the MOKAN Region is not scheduled for service until April 1983.

Eight of the electric systems included in the MOKAN Region are members of the MOKAN Pool, which is a formal organization formed to achieve operating economies and reliability through coordinated planning and operations. As members of SPP, most of the Region adheres to the SDPP planning reserve criteria of 15 percent of peak demand although several of the MOKAN Pool members are now planning for a 20 percent reserve margin. Table 8C.4.1 and 8C.4.2 present the actual reserve situations that occurred in the MOKAN Region for 1977 through 1979 for three summer months and three winter months. It is noted that total reserves during the summer peak periods varied from a low of 26.8 percent of peak demand in July 1977 to a high of 52.6 percent in June 1979. Actual reserves varied from a low of 13.8 percent in July 1978 to a high of 29.1 percent in June 1979. The amount of generating capacity out of service during the peak months as a percent of the peak demand was 8.9 percent in July 1977, 8.9 percent in August 1978, and 17 percent in August 1979.

The MOKAN Region is strongly interconnected internally through backbone 345 kV transmission circuits which were constructed mainly

after the MOKAN Coordination Agreement was signed. The Region is also strongly interconnected with the Oklahoma Region of SPP and the MAIN Reliability Council. During 1977, 1978, and 1979, MOKAN was a net purchaser of energy in the amounts of 2,292 GWh, 2,027 GWh and 3,108 GWh, respectively.

The members of the MOKAN Coordination Group instituted a manual economy energy brokerage system on March 3, 1980, in order to maximize economy energy transactions among the members. The system is planned to be computerized in the near future.

Current Perspective

The Missouri-Kansas Group is projecting the addition of 1,565 MW of coal-fired capacity by the 1980 summer peak period. There are presently no delays anticipated for the three projected units.

The reserves for the upcoming summer and winter peak appear excellent. Actual reserves (assuming scheduled maintenance, inoperable capability and ERA-estimated forced outages) would be 13.1 percent in the summer and 46.9 percent in the winter (see Table 8C.5).

The total generating resources, 13,121 MW, during the 1980 summer period include 69.7 percent coal-fired generation, 20.9 percent gas-fired, 9.3 percent oil-fired, and 0.1 percent hydroelectric as shown on Table 8C.9.

During 1980, the systems in MOKAN plan to place one 345-kV line and one 230/345-kV line in operation. Total circuit miles to be installed are 86. Both circuits are intra-regional and are needed to deliver the generator output of new coal-fired capacity.

Future Perspective

The MOKAN Region is expecting 1,590 MW of additional coal-fired capacity and a 955 MW share of a nuclear unit in the 1981-1984 time period. The Wolf Creek No. 1 nuclear unit is projected by NRC to be delayed one year to 1984 from what was predicted in the 1980 ERA-411. It is estimated by ERA that the 280 MW Holcomb No. 1 coal-fired unit might also be delayed one year to 1984.

Total reserves are projected to range from 21.8 percent to 29.5 percent for the summer peak periods (see Table 8C.6). Winter reserves, for all cases, are excellent. Available reserves (which include scheduled maintenance and inoperable capability) would range from 20.2 percent to 28.1 percent. With estimated forced outages, the actual reserves would range from 7.7 percent to 15.5 percent. These

reserves appear adequate. The projected nuclear and coal-fired delay totaling 1,235 MW in 1983 would result in low summer peak actual reserves of 5.4 percent in 1983. This figure also appears adequate.

The Region currently has several 345-kV interconnections with Middle South Utilities, ILLMO Region, MAPP, and the Oklahoma Group. Additional 345-kV interconnections are projected with MAPP in 1981 and 1983 for the purpose of increasing interchange capability. In addition to these inter-regional ties, a 230-kV interconnection to the Oklahoma Group is planned for 1984 for the purpose of increasing interchange capability. MOKAN plans to construct 378 miles of 345-kV circuits and 322 miles of 230-kV circuits during this 4-year period, all intra-regional. The purpose of the intra-regional lines in order of importance is to deliver generator output, increase interchange capability, provide for local area protection, and relieve overload.

In this time frame, MOKAN is projecting 1,930 MW of additional coal-fired capacity and a 250 MW share of a nuclear unit.

Actual reserves are projected to be from 13.6 percent to 23.6 percent for the summer peak period (see Table 8C.7). With a projected nuclear unit delay, these reserves would range from 12.0 to 23.6 percent.

A 345-kV tie with the MAPP Region is projected for 1986 for increased interchange capability. Intra-regional transmission line construction is projected to include 387 miles of 345-kV circuits and 209 miles of 230-kV circuits. The purpose of the majority of these lines is for increased interchange capability and area protection.

The Missouri-Kansas Group appears to be in a very reliable state throughout the entire decade, barring any unforeseen occurrences.

During the 10-year report period (1980-1989), the MOKAN Group is projecting its summer peak demand, winter peak demand, and annual energy requirement to have average annual growth rates of 4.4 percent, 5.0 percent and 4.5 percent, respectively. Annual load factor is expected to vary slightly during this period from 49.8 percent in 1980 to 51.8 percent in 1989. Table 8C.8 gives a list of the estimated amounts and annual growth rates.

The MOKAN Group is less dependent on natural gas and oil for boiler fuel than the other three groups within the SPP. As shown on Table 8C.9, gas and oil capacity represents 30.2 percent of the total generating resources during the summer of 1980 and is projected to be 21.1 percent in 1989. The disruption of natural gas and oil supplies would present some problems for the MOKAN system in meeting its energy requirements; however, the impact would be less severe than in the other Regions.

Table 8C.3

HISTORICAL LOAD GROWTH
Missouri-Kansas Group (Region 21)

	<u>- D e m a n d -</u>				<u>Annual Energy Requirements</u>		<u>Annual Load Factor</u> (%)
	<u>Summer</u> (MW)	<u>Growth</u> (%)	<u>Winter</u> (MW)	<u>Growth</u> (%)	<u>Amount</u> (GWh)	<u>Growth</u> (%)	
1977	7,966	-	5,587	-	34,624	-	49.6
1978	8,454	6.13	5,772	3.31	37,086	7.11	50.1
1979	8,103	-4.15	5,617	-2.69	36,826	-0.70	51.9

Table 8C.4.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Missouri-Kansas Group

	S			U			M			E			R		
	1 9 7 7			1 9 7 8			1 9 7 9								
	Jun	Jul	Aug	Jun	Jul	Aug	Jun	Jul	Aug	Jun	Jul	Aug	Jun	Jul	Aug
1. Planned Capability	9859	9888	9907	9829	9829	10173	10343	10392	10392						
2. Peak Demand	6843	7966	7635	7387	8337	8454	7309	7816	8103						
3. Planned Reserves (1-2)	3016	1922	2272	2442	1492	1719	3034	2576	2289						
4. Planned Reserves (%) (3/2)x100	44.1	24.1	29.8	33.1	17.9	20.3	41.5	33.0	28.2						
5. Net Transactions (Imports-Exports)	481	213	1165	662	787	922	814	1075	751						
6. Total Capability (1+5)	10340	10101	11072	10491	10616	11095	11157	11467	11143						
7. Total Reserves (6-2)	3497	2135	3437	3104	2279	2641	3848	3651	3040						
8. Total Reserves (%) (7/2)x100	51.1	26.8	45.0	42.0	27.3	31.2	52.6	46.7	37.5						
9. Scheduled Maintenance	1447	34	42	447	147	122	694	512	177						
10. Capability after Maintenance (6-9)	8893	10067	11030	10044	10469	10973	10463	10955	10966						
11. Reserves after Maintenance (10-2)	2050	2101	3395	2657	2132	2519	3154	3139	2863						
12. Reserves after Maintenance (%) (11/2)x100	30.0	26.4	44.5	36.0	25.6	29.8	43.2	40.2	35.3						
13. Inoperable Capability	576	350	315	267	807	403	389	402	431						
14. Available Capability (10-13)	8317	9717	10715	9783	9662	10570	10074	10553	10535						
15. Available Reserves (14-2)	1474	1751	3080	2396	1325	2116	2765	2737	2432						
16. Available Reserves (%) (15/2)x100	21.5	22.0	40.3	32.4	15.9	25.0	37.8	35.0	30.0						
17. Forced Outages	206	360	1145	1228	171	351	638	662	945						
18. Actual Capability after Forced Outages (14-17)	8111	9357	9570	8555	9491	10219	9436	9891	9590						
19. Actual Reserves (18-2)	1268	1391	1935	1168	1154	1765	2127	2075	1487						
20. Actual Reserves (%) (19/2)x100	18.5	17.5	25.3	15.8	13.8	20.9	29.1	26.5	18.4						

Table 8C.4.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Missouri-Kansas Group

	----- W ----- I ----- N ----- T ----- E ----- R -----								
	1977/78			1978/79			1979/80		
	Dec	Jan	Feb	Dec	Jan	Feb	Dec	Jan	Feb
1. Planned Capability	9840	9846	9846	10121	10333	10333	10451	10442	10399
2. Peak Demand	5466	5587	5508	5634	5772	5767	5617	5571	5528
3. Planned Reserves (1-2)	4374	4259	4338	4487	4561	4566	4834	4871	4871
4. Planned Reserves (%) (3/2)x100	80.0	76.2	78.8	79.6	79.0	79.2	86.1	87.4	88.1
5. Net Transactions (Imports-Exports)	-98	17	-94	566	576	460	984	-124	239
6. Total Capability (1+5)	9742	9863	9752	10687	10909	10793	11435	10318	10638
7. Total Reserves (6-2)	4276	4276	4244	5053	5137	5026	5818	4747	5110
8. Total Reserves (%) (7/2)x100	78.2	76.5	77.1	89.7	89.0	87.2	103.6	85.2	92.4
9. Scheduled Maintenance	1413	738	482	1457	775	973	1711	1256	959
10. Capability after Maintenance (6-9)	8329	9125	9270	9230	10134	9820	9724	9062	9679
11. Reserves after Maintenance (7-9)	2863	3538	3762	3596	4362	4053	4107	3491	4151
12. Reserves after Maintenance (%) (11/2)x100	52.4	63.3	68.3	63.8	75.6	70.3	73.1	62.7	75.1
13. Inoperable Capability	603	1040	434	632	355	583	340	344	264
14. Available Capability (10-13)	7726	8085	8836	8598	9779	9237	9384	8718	9415
15. Available Reserves (14-2)	2260	2498	3328	2964	4007	3470	3767	3147	3887
16. Available Reserves (%) (15/2)x100	41.3	44.7	60.4	52.6	69.4	60.2	67.1	56.5	70.3
17. Forced Outages	160	255	920	450	1615	841	1156	351	1059
18. Actual Capability after Forced Outages (14-17)	7566	7830	7916	8148	8164	8396	8228	8367	8356
19. Actual Reserves (18-2)	2100	2243	2408	2514	2392	2629	2611	2796	2828
20. Actual Reserves (%) (19/2)x100	38.4	40.1	43.7	44.6	41.4	45.6	46.5	50.2	51.2

Table 8C.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Missouri-Kansas Group

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	13121	13110
2. Peak Demand	10674	7874
3. Planned Reserves (1-2)	2447	5236
4. Planned Reserves (%) (3/2)x100	22.9	66.5
5. Net Transactions (Imports-Exports)	429	430
6. Total Capability (1+5)	13550	13540
7. Total Reserves (6-2)	2876	5666
8. Total Reserves (%) (7/2)x100	26.9	72.0
9. Scheduled Maintenance	44	183
10. Capability after Maintenance (6-9)	13506	13357
11. Reserves after Maintenance (10-2)	2832	5483
12. Reserves after Maintenance (%) (11/2)x100	26.5	69.6
13. Inoperable Capability	96	105
14. Available Capability (10-13)	13410	13252
15. Available Reserves (14-2)	2736	5378
16. Available Reserves (%) (15/2)x100	25.6	68.3
17. Forced Outages <u>2/</u>	1338	1683
18. Actual Capability after Forced Outages (14-17)	12072	11569
19. Actual Reserves (18-2)	1398	3695
20. Actual Reserves (%) (19/2)x100	13.1	46.9

1/ No delays are anticipated in new generating units since submission of ERA-411.

2/ Estimated by ERA staff based on historical amounts.

Table 8C.6

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Missouri-Kansas Group

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	13207	13238	13864	13865	15490	15491	15474	15491
2. Peak Demand	11183	8308	11694	8727	12245	9179	12791	9620
3. Planned Reserves (1-2)	2024	4930	2170	5138	3245	6312	2683	5871
4. Planned Reserves (%) (3/2)x100	18.1	59.3	18.6	58.9	26.5	68.8	21.0	61.0
5. Net Transactions (Imports-Exports)	413	420	439	451	373	425	304	408
6. Total Capability (1+5)	13620	13658	14303	14316	15863	15916	15778	15899
7. Total Reserves (6-2)	2437	5350	2609	5589	3618	6737	2987	6279
8. Total Reserves (%) (7/2)x100	21.8	64.4	22.3	64.0	29.5	73.4	23.4	65.3
9. Scheduled Maintenance	83	436	60	537	83	472	60	651
10. Capability after Maintenance (8-9)	13537	13222	14243	13779	15780	15444	15718	15248
11. Reserves after Maintenance (10-2)	2354	4914	2549	5052	3535	6265	2927	5628
12. Reserves after Maintenance (%) (11/2)x100	21.0	59.1	21.8	57.9	28.9	68.3	22.9	58.5
13. Inoperable Capability	96	105	96	105	96	105	96	89
14. Available Capability (10-13)	13441	13117	14147	13674	15684	15339	15622	15159
15. Available Reserves (14-2)	2258	4809	2453	4947	3439	6160	2831	5539
16. Available Reserves (%) (15/2)x100	20.2	57.9	21.0	56.7	28.1	67.1	22.1	57.6
17. Forced Outages	1400	1774	1471	1869	1545	1972	1618	2087
18. Actual Capability after Forced Outages (14-17)	12041	11343	12676	11805	14139	13367	14004	13072
19. Actual Reserves (18-2)	858	3035	982	3078	1894	4188	1213	3452
20. Actual Reserves (%) (19/2)x100	7.7	36.5	8.4	35.3	15.5	45.6	9.5	35.9

XI.8.38

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	955	955	0	0
22. Actual Capability (18-21)	12041	11343	12676	11805	13184	12412	14004	13072
23. Actual Reserves with Nuclear Delays (22-2)	858	3035	982	3078	939	3233	1213	3452
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	7.7	36.5	8.4	35.3	7.7	35.2	9.5	35.9

Coal Unit Delays Assumed Possible by ERA

25. Possible Coal Delays	0	0	0	0	280	280	280	280
26. Actual Capability w/Nuclear & Coal Delays (22-25)	12041	11343	12676	11805	12904	12132	13724	12792
27. Actual Reserves w/Nuclear & Coal Delays (25-2)	858	3035	982	3078	659	2953	933	33.0
28. Actual Reserves w/Nuclear & Coal Delays (%) (27/2)x100	7.7	36.5	8.4	35.3	5.4	32.2	7.3	33.0

1/ Estimated by ERA staff based on historical forced outage amounts.

Table 8C.7

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Missouri-Kansas Group

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	16331	16328	16595	16659	16959	17163	17199	17263	17716	17776
2. Peak Demand	13357	10157	13884	10640	14493	11153	15109	11695	15756	12188
3. Planned Reserves (1-2)	2974	6171	2711	6019	2466	6010	2090	5568	1960	5588
4. Planned Reserves (%) (3/2)x100	22.3	60.8	19.5	56.6	17.0	53.9	13.8	47.6	12.4	45.8
5. Net Transactions (Imports-Exports)	230	395	151	277	122	253	210	348	175	317
6. Total Capability (1+5)	16611	16723	16746	16936	17081	17416	17409	17611	17891	18093
7. Total Reserves (6-2)	3254	6566	2862	6296	2588	6263	2300	5916	2135	5905
8. Total Reserves (%) (7/2)x100	24.4	64.6	20.6	59.2	17.9	56.2	15.2	50.6	13.6	48.4
9. Scheduled Maintenance	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	16611	16723	16746	16936	17081	17416	17409	17611	17891	18093
11. Reserves after Maintenance (10-2)	3254	6566	2862	6296	2588	6263	2300	5916	2135	5905
12. Reserves after Maintenance (%) (11/2)x100	24.4	64.6	20.6	59.2	17.9	56.2	15.2	50.6	13.6	48.4
13. Inoperable Capability	96	89	0	40	0	40	0	40	0	40
14. Available Capability (10-13)	16515	16634	16746	16896	17081	17376	17409	17571	17891	18053
15. Available Reserves (14-2)	3158	6477	2862	6256	2588	6223	2300	5876	2135	5865
16. Available Reserves (%) (15/2)x100	23.6	63.8	20.6	58.8	17.9	55.8	15.2	50.2	13.6	48.1
17. Forced Outages	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	16515	16634	16747	16896	17081	17376	17409	17571	17891	18053
19. Actual Reserves (18-2)	3158	6477	2862	6256	2588	6223	2300	5876	2135	5865
20. Actual Reserves (%) (19/2)x100	23.6	63.8	20.6	58.8	17.9	55.8	15.2	50.2	13.6	48.1
<u>Nuclear Unit Delays as Projected by Nuclear Regulation Commission</u>										
21. Nuclear Delays	0	0	0	0	250	250	250	250	250	250
22. Actual Capability (18-21)	16515	16634	16746	16896	16831	17126	17159	17321	17641	17803
23. Actual Reserves with Nuclear Delays (22-2)	3158	6477	2862	6256	2338	5973	2050	5626	1885	5615
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	23.6	63.8	20.6	58.8	16.1	53.6	13.6	48.1	12.0	46.1

XI.8.39

1/ Information on Scheduled Maintenance and Forced Outages not available for the 1985/89 time period.

Table 8C.8

FUTURE LOAD GROWTH
Missouri-Kansas Group

	<u>- D e m a n d -</u>				<u>Energy Requirements</u>		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	10,674	-	7,874	-	46,665	-	49.8
1981	11,183	4.8	8,308	5.5	49,014	5.0	50.0
1982	11,694	4.6	8,727	5.0	51,353	4.8	50.1
1983	12,245	4.7	9,179	5.2	54,037	5.2	50.4
1984	12,791	4.5	9,620	4.9	56,669	4.9	50.4
1985	13,357	4.4	10,157	4.7	59,355	4.7	50.7
1986	13,884	3.9	10,640	4.8	62,197	4.8	51.1
1987	14,493	4.4	11,153	5.0	65,337	5.0	51.5
1988	15,109	4.3	11,695	4.6	68,347	4.6	51.5
1989	15,756	<u>4.3</u>	12,188	<u>4.7</u>	71,533	<u>4.7</u>	51.8
1980-89		4.4		5.0		4.9	

Table 8C.9

GENERATION MIX BY FUEL TYPE
Missouri-Kansas Group

Type Fuel	Summer 1980		Summer 1985		Summer 1989	
	Capability (MW)	% of Total (%)	Capability (MW)	% of Total (%)	Capability (MW)	% of Total (%)
Nuclear	0	-	955	5.8	1,205	6.8
Coal	9,147	69.7	11,417	69.9	12,667	71.5
Gas	2,743	20.9	2,486	15.2	2,257	12.7
Oil	1,215	9.3	1,457	9.0	1,488	8.4
Hydro	16	0.1	16	-	16	0.1
Other	<u>0</u>	<u>-</u>	<u>0</u>	<u>-</u>	<u>83</u>	<u>0.5</u>
Total	13,121	100.0	16,331	100.0	17,716	100.0

Oklahoma Group (Region 22)Historical Perspective

The Oklahoma Group includes all of Oklahoma and portions of Arkansas, Louisiana, New Mexico, and Texas. The Region has been a predominantly natural gas burning area, but it does use some coal and a little oil. As has occurred in most areas of the country, the growth rates for demand and energy have been declining. The historical growth rates are listed in Table 8D.1.

Table 8D.1

Compound Annual Growth Rates
Oklahoma Group

<u>Period</u>	<u>Peak Demand</u> (%)	<u>Annual Energy</u> (%)
1950-1960	12.0	11.6
1960-1970	8.7	8.6
1970-1976	6.5	7.2

In addition, the historical growth rates from 1977 to 1979 have shown an even more drastic decrease (see Table 8D.3). The 1979 peak demand and annual energy were less than 1978 figures with growth rates of -3.88 percent and -0.53 percent, respectively.

Tables 8D.4.1 and 8D.4.2 show the 1977-79 actual reserves for three summer and three winter months. The Oklahoma Group has had total reserves that ranged from 19.8 percent to 32.6 percent during the summer, and actual reserves that ranged from 16.9 percent to 22.9 percent.

Table 8D.2 shows the capacity mix by fuel type and the generation by fuel type for 1979.

Table 8D.2

Capacity Mix and Generation by Fuel Type for 1979
Oklahoma Group

<u>Fuel Type</u>	<u>Capacity</u>		<u>Annual Generation</u>	
	(GWh)	(% of Total)	(GWh)	(% of Total)
Coal	3,458	19.2	13,554.9	18.6
Oil	293	1.6	166.2	0.2
Natural Gas	11,767	65.5	52,953.7	72.7
Nuclear	-0-	0.0	-0-	0.0
Hydro	2,438	13.5	6,075.5	8.4
Other *	42	0.2	85.5	0.1
Total	17,998	100.0	72,835.8	100.0

* Includes a co-generation unit and an expander turbine using hot inert gas from a chemical process.

During the 1980-89 period, the Oklahoma Region is projecting 9,259 MW of additional coal-fired capacity, 900 MW of nuclear capacity (Black Fox No. 1) and 214 MW of hydro capacity. This will result in the following capacity mix, by the winter of 1989-90, as a percent of the total: Coal - 48.2 percent, oil - 1.1 percent, natural gas - 36.7 percent, nuclear - 3.5 percent, hydro - 10.3 percent, and other - 0.2 percent.

The Oklahoma Region has, for the 1977-79 summer and winter periods, been a net seller of power. This is due in part to the Department of Energy's Southwestern Power Administration which sells power to the MOKAN systems (Region 21) and Middle South Systems (Region 8). For the entire Region 22, net energy sales were 5,939.8 GWh for 1977, 9,735.0 GWh for 1978, and 13,039.7 GWh in 1979, which constitutes 9.6 percent, 14.1 percent, and 18.1 percent of their system's net generation, respectively.

Current Perspective

The Oklahoma Group is projecting 866 MW of coal-fired capacity in service by the 1980 summer peak and an additional 965 MW by the winter peak. There are no anticipated delays of these units.

Total, available, and actual reserves appear adequate for the summer and winter periods as shown on Table 8D.5. Total reserves will be 25.1 percent and 71.7 percent for the summer and winter, respectively. There is no scheduled maintenance or inoperable capability projected for the 1980 summer and 126 MW of scheduled maintenance for the winter. This results in available reserves of 25.1 percent for the summer and 70.4 percent for the winter. Estimated forced outages based on historical forced outage trends would result in actual reserves of 20.4 percent and 62.2 percent for the summer and winter, respectively.

Table 8D.9 provides projected generation mix by fuel type during the summers of 1980, 1985, and 1989. During the 1980 summer peaking period, the Oklahoma Group plans to have 4,324 MW of coal-fired capability, 10,790 MW fired by natural gas, 295 MW by oil, 2,542 MW of hydro capability and 42 MW of other (includes a co-generation unit and an expander turbine using hot inert gas).

Future Perspective

The Oklahoma Group is projecting a peak demand growth rate of 5.5 percent for the 1981-1984 period. This is slightly higher than the 5.2 percent growth rate for the 1985-1989 period. As stated previously in the Historical Perspective, most of the capacity additions in the 1980-1989 period will be coal-fired. During the 1981-1984 period, 2,417 MW of coal-fired capacity and 58 MW of hydro capacity is projected. Due to the limited number of viable hydroelectric sites remaining, hydro will not play much of a role in future capacity expansion plans.

Total reserves for the summer peak (which are based upon planned generating resources and any power purchases and sales) are projected to range from 18.4 percent to 28.9 percent (see Table 8D.6). This is above the SPP criteria of

15 percent. Available reserves (which show the effect of scheduled maintenance and any inoperable capability) will range from 17.2 percent to 28.9 percent. Again, this is well above the criteria.

Actual reserves (which reduce available reserves by estimated forced outages) range from 13.7 percent to 24.2 percent. This is considerably above the SPP actual reserve criteria of 6 percent. The forced outages were estimated using 1977-1979 historical outage rates obtained from Form 12E-2 data. This average summer rate was approximately 4.7 percent for Region 22.

In addition, possible nuclear and coal unit delays were examined to see what effect they might have on operating reserves. There were no nuclear delays expected but it was estimated using status codes in ERA-411 and other available information that GRDA No. 1 (490 MW), Welsh No. 3 (528 MW), Hugo No. 1 (376 MW), and Tolk No. 1 (508 MW) may be delayed as much as one year each. This would result in 490 MW and 1,412 MW of additional capability unavailable for the 1981 and 1982 summer peaks, respectively. The resultant actual reserve margins for these two years would be 20.7 percent and 13.9 percent which would appear quite adequate.

The Region is interconnected via EHV transmission lines to the Middle South Group (500 kV) and to the Missouri-Kansas Group with two 345-kV lines.

A 345-kV tie with the Gulf States Group to relieve overloads is projected to 1981 and a 345-kV tie is proposed for 1983 with MOKAN in order to deliver Associated Electric Cooperative's share of the Black Fox No. 1 nuclear unit. In addition, two internal 345-kV lines and a 230-kV interconnection with MOKAN are projected for 1984 to increase interchange capability.

The Oklahoma Group should have adequate reserves to cover possible outages and possible unit delays during the 1981-1984 period.

Region 22 is projecting 5,011 MW of coal-fired capacity in the 1985-1989 period along with a 900 MW share of Black Fox No. 1 nuclear unit and 52 MW of hydro capacity.

Table 8D.7 shows that summer actual reserves will range from 17.9 percent to 21.4 percent. Reserves which do not include any estimated scheduled maintenance or forced outages, but do include projected nuclear delays range from 15.8 percent to 21.4 percent for the summer peak period. The Black Fox No. 1 unit is estimated to be delayed from its 1987 date beyond the 1989 period by NRC.

In addition to those transmission lines previously mentioned, the Oklahoma Group is projecting two 345-kV internal lines for 1986 to increase interchange capability.

The Oklahoma Group should have adequate reserves throughout the 1980-1989 period to cover all but abnormal circumstances.

During the 10-year period (1980-1989), the Oklahoma Group is projecting that its summer peak demand, winter peak demand and annual energy requirements will grow at an average rate of 5.4 percent, 5.7 percent, and 5.5 percent, respectively.

Table 8D.8 presents the numerical estimates and shows annual projected growths for each of the three items. Table 8D.8 also shows the calculated annual load factor. The Oklahoma Group is projecting that its annual load factor will remain fairly constant at a 54 percent level throughout the period.

In order for annual energy requirements to be served by the Region, an adequate supply of natural gas must be maintained. During the 1989 summer peak period, it is projected that 38.6 percent of the Region's generating capability will be fueled by natural gas (see Table 8D.9).

Table 8D.3

HISTORICAL LOAD GROWTH

Oklahoma Group (Region 22)

	- D e m a n d -				Annual Energy Requirements		Annual Load Factor (%)
	<u>Summer (MW)</u>	<u>Growth (%)</u>	<u>Winter (MW)</u>	<u>Growth (%)</u>	<u>Amount (GWh)</u>	<u>Growth (%)</u>	
1977	12,010	-	9,403	-	56,246	-	53.5
1978	12,576	4.71	9,156	-2.63	59,429	5.66	53.9
1979	12,088	-3.88	8,981	-1.95	59,115	-0.53	55.8

Table 8D.4.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	<u>S</u>			<u>U</u>	<u>M</u>	<u>M</u>	<u>E</u>	<u>R</u>	
	1 9 7 7			1 9 7 8			1 9 7 9		
	Jun	Jul	Aug	Jun	Jul	Aug	Jun	Jul	Aug
1. Planned Capability	14655	14650	14681	15825	16140	16131	16530	16527	16526
2. Peak Demand	10698	12010	11625	11716	12576	12561	11460	11941	12088
3. Planned Reserves (1-2)	3957	2640	3056	4109	3564	3570	5070	4586	4438
4. Planned Reserves (%) (3/2)x100	37.0	22.0	26.3	35.1	28.3	28.4	44.2	38.4	36.7
5. Net Transactions (Imports-Exports)	-722	-260	-558	-1037	-1070	-907	-1455	-694	-537
6. Total Capability (1+5)	13933	14390	14123	14788	15070	15224	15075	15833	15989
7. Total Reserves (6-2)	3235	2380	2498	3072	2494	2663	3615	3892	3901
8. Total Reserves (%) (7/2)x100	30.2	19.8	21.5	26.2	19.8	21.2	31.5	32.6	32.3
9. Scheduled Maintenance	216	18	0	477	18	137	762	423	35
10. Capability after Maintenance (6-9)	13717	14372	14123	14311	15052	15087	14313	15410	15954
11. Reserves after Maintenance (10-2)	3019	2362	2498	2595	2476	2526	2853	3469	3866
12. Reserves after Maintenance (%) (11/2)x100	28.2	19.7	21.5	22.1	19.7	20.1	24.9	29.1	32.0
13. Inoperable Capability	198	148	156	33	152	271	82	225	187
14. Available Capability (10-13)	13519	14224	13967	14278	14900	14816	14231	15185	15767
15. Available Reserves (14-2)	2821	2214	2342	2562	2324	2255	2771	3244	3679
16. Available Reserves (%) (15/2)x100	26.4	18.4	20.1	21.9	18.5	18.0	24.2	27.2	30.4
17. Forced Outages	538	94	281	583	170	128	152	694	1159
18. Actual Capability after Forced Outages (14-17)	12981	14130	13686	13695	14730	14688	14079	14491	14608
19. Actual Reserves (18-2)	2283	2120	2061	1979	2154	2127	2619	2550	2520
20. Actual Reserves (%) (19/2)x100	21.3	17.7	17.7	16.9	17.1	16.9	22.9	21.4	20.8

Table 8D.4.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	<u>1977/78</u>			<u>1978/79</u>			<u>1979/80</u>		
	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>
1. Planned Capability	15509	15474	15468	16655	16609	16599	17054	17473	17501
2. Peak Demand	8466	8705	9403	8844	9156	8932	8973	8981	8836
3. Planned Reserves (1-2)	7043	6769	6065	7811	7453	7667	8081	8492	8665
4. Planned Reserves (%) (3/2)x100	83.2	77.8	64.5	88.3	81.4	85.8	90.1	94.6	98.1
5. Net Transactions (Imports-Exports)	-1632	-2048	-1730	-2281	-1651	1642	-1795	-2349	-2704
6. Total Capability (1+5)	13877	13426	13738	14374	14958	14957	15259	15124	14797
7. Total Reserves (6-2)	5411	4721	4335	5530	5802	6025	6286	6143	5961
8. Total Reserves (%) (7/2)x100	63.9	54.2	46.1	62.5	63.4	67.5	70.1	68.4	67.5
9. Scheduled Maintenance	1676	1157	1874	1412	2086	1150	1738	1776	1013
10. Capability after Maintenance (6-9)	12201	12269	11864	12962	12872	13807	13521	13348	13784
11. Reserves after Maintenance (10-2)	3735	3564	2461	4118	3716	4875	4548	4367	4948
12. Reserves after Maintenance (%) (11/2)x100	44.1	40.9	26.2	46.6	40.6	54.6	50.7	48.6	56.0
13. Inoperable Capability	138	57	31	58	98	215	141	46	199
14. Available Capability (10-13)	12063	12212	11833	12904	12774	13592	13380	13302	13585
15. Available Reserves (14-2)	3597	3507	2430	4060	3618	4660	4407	4321	4749
16. Available Reserves (%) (15/2)x100	42.5	40.3	25.8	45.9	39.5	52.2	49.1	48.1	53.7
17. Forced Outages	864	474	440	163	632	1397	908	584	198
18. Actual Capability after Forced Outages (14-17)	11199	11738	11393	12741	12142	12195	12472	12718	13387
19. Actual Reserves (18-2)	2733	3033	1990	3897	2986	3263	3499	3737	4551
20. Actual Reserves (%) (19/2)x100	32.3	34.8	21.2	44.1	32.6	36.5	39.0	41.6	51.5

Table 8D.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	<u>1980</u> <u>Summer</u>	<u>1980/81</u> <u>Winter</u>
1. Planned Capability <u>1/</u>	17993	18819
2. Peak Demand	13391	9776
3. Planned Reserves (1-2)	4602	9043
4. Planned Reserves (%) (3/2)x100	34.4	92.5
5. Net Transactions (Imports-Exports)	-1240	-2038
6. Total Capability (1+5)	16753	16781
7. Total Reserves (6-2)	3362	7005
8. Total Reserves (%) (7/2)x100	25.1	71.7
9. Scheduled Maintenance	0	126
10. Capability after Maintenance (6-9)	16753	16655
11. Reserves after Maintenance (10-2)	3362	6879
12. Reserves after Maintenance (%) (11/2)x100	25.1	70.4
13. Inoperable Capability	0	0
14. Available Capability (10-13)	16753	16655
15. Available Reserves (14-2)	3362	6879
16. Available Reserves (%) (15/2)x100	25.1	70.4
17. Forced Outages <u>2/</u>	629	802
18. Actual Capability after Forced Outages (14-17)	16124	15853
19. Actual Reserves (18-2)	2733	6077
20. Actual Reserves (%) (19/2)x100	20.4	62.2

1/ No Nuclear Unit delays.

2/ Estimated by ERA staff based on historical forced outage amounts.

Table 8D.6

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Oklahoma Group (Region 22)

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	19510	19370	20975	20792	20881	20763	20783	21085
2. Peak Demand	14110	10277	14908	10942	15757	11634	16607	12317
3. Planned Reserves (1-2)	5400	9093	6067	9850	5124	9129	4176	8768
4. Planned Reserves (%) (3/2)x100	38.3	88.5	40.7	90.0	32.5	78.5	25.1	71.2
5. Net Transactions (Imports-Exports)	-1324	-2337	-1876	-2208	-1460	-1559	-1119	-1295
6. Total Capability (1+5)	18186	17033	19099	18584	19421	19204	19664	19790
7. Total Reserves (6-2)	4076	6756	4191	7642	3664	7570	3057	7473
8. Total Reserves (%) (7/2)x100	28.9	65.7	28.1	69.8	23.3	65.1	18.4	60.7
9. Scheduled Maintenance	0	337	0	561	0	661	0	775
10. Capability after Maintenance (6-9)	18186	16696	19099	18023	19421	18543	19664	19015
11. Reserves after Maintenance (10-2)	4076	6419	4191	7081	3664	6909	3057	6698
12. Reserves after Maintenance (%) (11/2)x100	28.9	62.5	28.1	64.7	23.3	59.4	18.4	54.4
13. Inoperable Capability	0	0	193	193	193	193	193	193
14. Available Capability (10-13)	18186	16696	18906	17830	19228	18350	19471	18822
15. Available Reserves (14-2)	4076	6419	3998	6888	3471	6716	2864	6505
16. Available Reserves (%) (15/2)x100	28.9	62.5	26.8	63.0	22.0	57.7	17.2	52.8
17. Forced Outages	663	843	508	704	548	761	588	817
18. Actual Capability after Forced Outages (14-17)	17523	15853	18398	17126	18680	17589	18883	18005
19. Actual Reserves (18-2)	3413	5576	3490	6184	2923	5955	2276	5688
20. Actual Reserves (%) (19/2)x100	24.2	54.3	23.4	56.5	18.6	51.2	13.7	46.2

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	0	0	0	0
22. Actual Capability (18-21)	17523	15853	18398	17126	18680	17589	18883	18005
23. Actual Reserves with Nuclear Delays (22-2)	3413	5576	3490	6184	2923	5955	2276	5688
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	24.2	54.3	23.4	56.5	18.6	51.2	13.7	46.2

Coal Unit Delays Assumed Possible by ERA

25. Possible Coal Delays	490	490	1412	1412	0	0	0	0
26. Actual Capability w/Nuclear & Coal Delays (22-25)	17033	15363	16986	15714	18680	17589	18883	18005
27. Actual Reserves w/Nuclear & Coal Delays (26-2)	2923	5086	2078	4772	2923	5955	2276	5688
28. Actual Reserves w/Nuclear & Coal Delays (%) (27/2)x100	20.7	49.5	13.9	43.6	18.6	51.2	13.7	46.2

1/ Estimated by ERA staff based on historical forced outage amounts.

Table 80.7

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Oklahoma Group (Region 22)

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22526	22487	23336	22965	24947	24908	25879	25541	26940	26720
2. Peak Demand	17517	13042	18464	13812	19421	14563	20406	15349	21431	16163
3. Planned Reserves (1-2)	5009	9445	4872	9153	5526	10345	5473	10192	5509	10557
4. Planned Reserves (%) (3/2)x100	28.6	72.4	26.4	66.3	28.5	71.0	26.8	66.4	25.7	65.3
5. Net Transactions (Imports-Exports)	-1068	-1244	-1369	-1645	-1333	-1609	-1236	-1512	-1132	-1408
6. Total Capability (1+5)	21458	21243	21967	21320	23614	23299	24643	24029	25808	25312
7. Total Reserves (6-2)	3941	8201	3503	7508	4193	8736	4237	8680	4377	9149
8. Total Reserves (%) (7/2)x100	22.5	62.9	19.0	54.4	21.6	60.0	20.8	56.6	20.4	56.6
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	21458	21243	21967	21310	23614	23299	24643	24029	25808	25312
11. Reserves after Maintenance (10-2)	3941	8201	3503	7508	4193	8736	4237	8680	4377	9149
12. Reserves after Maintenance (%) (11/2)x100	22.5	62.9	19.0	54.4	21.6	60.0	20.8	56.6	20.4	56.5
13. Inoperable Capability	193	193	193	193	157	157	119	119	83	83
14. Available Capability (10-13)	21265	21050	21774	21127	23457	23142	24524	23910	25725	25229
15. Available Reserves (14-2)	3748	8008	3310	7315	4036	8579	4118	8561	4294	9066
16. Available Reserves (%) (15/2)x100	21.4	61.4	17.9	53.0	20.8	58.9	20.2	55.8	20.0	56.1
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	21265	21050	21774	21127	23457	23142	24524	23910	25725	25229
19. Actual Reserves (18-2)	3748	8008	3310	7315	4036	8579	4118	8561	4294	9066
20. Actual Reserves (%) (19/2)x100	21.4	61.4	17.9	53.0	20.8	58.9	20.2	55.8	20.0	56.1

XI.8.52

Nuclear Unit Delays as Projected by Nuclear Regulation Commission

21. Nuclear Delays	0	0	0	0	900	900	900	900	900	900
22. Actual Capability with Nuclear Delays (18-21)	21265	21050	21774	21127	22557	22242	23624	23010	24825	24329
23. Actual Reserves with Nuclear Delays (22-2)	3748	8008	3310	7315	3136	7679	3218	761	3394	8166
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	21.4	61.4	17.9	53.0	16.1	52.7	15.8	49.9	15.8	50.5

1/ Information on Scheduled Maintenance and Forced Outages not available for the 1985/89 period.

NOTE: No Coal Unit Delays Anticipated by ERA.

Table 8D.8

FUTURE LOAD GROWTH
Oklahoma Group (Region 22)

	- D e m a n d -				Energy Requirements		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	13,391	-	9,776	-	63,100	-	53.6
1981	14,110	5.4	10,277	5.1	66,800	5.9	54.0
1982	14,908	5.7	10,942	6.5	70,500	5.5	54.0
1983	15,757	5.7	11,634	6.3	74,300	5.4	53.8
1984	16,607	5.4	12,317	5.9	78,400	5.5	53.7
1985	17,517	5.5	13,042	5.9	82,800	5.6	54.0
1986	18,464	5.4	13,812	5.9	87,300	5.4	54.0
1987	19,421	5.2	14,563	5.4	92,000	5.4	54.1
1988	20,406	5.1	15,349	5.4	96,800	5.2	54.0
1989	21,431	<u>5.0</u>	16,163	<u>5.3</u>	101,900	<u>5.3</u>	54.3
1980-89		5.4		5.7		5.5	

Table 8D.9

GENERATION MIX BY FUEL TYPE
Oklahoma Group (Region 22)

Type Fuel	Summer 1980		Summer 1985		Summer 1989	
	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)	<u>Capability</u> (MW)	<u>% of Total</u> (%)
Nuclear	0	-	0	-	900	3.3
Coal	4,324	24.0	8,854	39.3	12,717	47.2
Gas	10,790	60.0	10,739	47.6	10,394	38.6
Oil	295	1.6	239	1.1	235	0.9
Hydro	2,542	14.2	2,652	11.8	2,652	9.8
Other	<u>42</u>	<u>0.2</u>	<u>42</u>	<u>0.2</u>	<u>42</u>	<u>0.2</u>
Total	17,993	100.0	22,526	100.0	26,940	100.0

SECTION XI.9

WESTERN SYSTEMS COORDINATING COUNCIL

(WSCC)

Western Systems Coordinating Council (WSCC)Introduction

Western Systems Coordinating Council (WSCC) was organized in 1967 to promote bulk power system reliability through coordinated planning and operation. Present membership includes 47 Member Systems and 14 Affiliate Members. These utility systems provide substantially all of the electric service in the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming, as well as portions of Nebraska, South Dakota, West Texas, and the Provinces of Alberta and British Columbia, Canada 1/. The region extends over approximately 1.8 million square miles and represents a service area equivalent to more than onehalf of the contiguous land area of the United States.

The WSCC consists of five subregions or areas. These subregions are the Northwest Power Pool Area, consisting of the states of Washington, Oregon, Idaho, and Utah, and parts of Montana, Wyoming, Nevada and California; the Rocky Mountain Power Area, consisting of the states of Colorado and part of Wyoming, South Dakota, and Nebraska; the Arizona-New Mexico Power Area, consisting of the states of Arizona and parts of New Mexico and Texas; the Southern California-Nevada Power Area consisting of the southern portion of the states of California and Nevada; and the Northern California-Nevada Power Area, consisting of the northern portions of the states of California and Nevada. Electric Regions identified in this report are consistent with the WSCC Areas and may differ slightly from the ERA Electric Regions currently defined. Identification of reporting utilities within the respective Regions is attached.

1/ This report excludes Canadian portions of WSCC.

Table 9.1
Electric Regions Within WSCC

<u>WSCC Area</u>	<u>Electric Region</u>
Northwest Power Pool	25 and 30
Rocky Mountain Power Pool	24
Arizona-New Mexico Group	26
Southern California-Nevada Group	27
Northern California-Nevada Group	28

To the east WSCC abuts the mid-Continent Area Power Pool, the Southwest Power Pool and Electric Reliability Council of Texas; WSCC abuts Mexico to the South and Canada to the North.

Table 9.2

Utility Systems Within WSCC Electric Regions

Electric Regions 25 and 30

Northwest Power Pool Area (NWPP)

Bonniers Ferry
Bonneville Power Administration
B.C. Hydro & Power Authority
Bountiful, City of
Calgary Power Ltd.
Centralia, City of
Chelan County PUD
Cowlitz County PUD
Douglas County PUD
Eugene Water & Electric Board
Grant County PUD
Grays Harbor PUD
Idaho Power Company
Montana Power Company
Pacific Power & Light Company
Pend Oreille County PUD
Portland General Electric Company
Puget Sound Power & Light Company
Seattle City Light
Snohomish PUD
St. George, City
Tacoma City Light
U.S.V.P. - Pacific Northwest Region -
 BPA (So. Idaho System)
USUC Loads Wheeled by Utah Power & Light Co.
U.S. Corps of Engineers (North Pacific Div.)
Utah Power & Light Company
Washington Water Power Company
West Kootenay Power & Light Company

Table 9.2 (Cont'd)

Utility Systems Within WSCC Electric Regions

Electric Region 24

Rocky Mountain Power Area (RMPA)

Basin Electric Power Cooperative (Wyoming
and Black Hills Power and Light Company
Colorado Springs, City of
Colorado-Ute Electric Association
Lamar, City
Platte River Power Authority
Public Service Co. of Colorado
So. Colorado Power Division, Central
Telephone & Utilities Corp.
Tri-State Generation & Transmission
Association, Inc.
U.S.W.P. - Lower Missouri Region
U.S.W.P. - Upper Colorado Region
Western Area Power Administration
Denver Area
Western Area Power Administration
Salt Lake Area

Electric Region 26

Arizona-New Mexico Power Area (AZ-NM)

Arizona Electric Power Cooperative
Arizona Power Authority
Arizona Public Service Company
Citizens Utilities Company
El Paso Electric Company
Imperial Irrigation District
Los Alamos Systems
Navajo Tribal Utility Authority
Plains Electric G & T Cooperative
Public Service Co. of New Mexico
Salt River Project
San Carlos Irrigation project
Southern California Edison Company
(Blythe District)
Tucson Electric Power Company
U.S.W.P. - Lower Colorado Region (Including
USUC Loads in LC Region)
U.S.W.P. Rio Grande Project (SW Region)
Western Area Power Administration
Boulder City Area

Table 9.2 (Cont'd)

Utility Systems Within WSCC Electric Regions

Electric Region 27

Southern California-Nevade Power Area (S.CA-NV)

Anaheim, City of
 Burbank, City of
 California Dept. of Water Resources
 California-Pacific Utilities Company
 Glendale, City of
 Intermountain Consumer Power Association
 Lincoln County Power District
 Los Angeles Dept. of Water & Power, City of
 Metropolitan Water District/So. California
 Nevada Power Company
 Pasadena, City of
 Riverside, City of
 San Diego Gas & Electric Company
 Southern California Edison Company
 State of Nevada
 U.S.W.P. at Boulder City

Electric Region 28

Northern California-Nevade Power Area (N.CA-NV)

California Dept. of Water Resources
 Pacific Gas & Electric Company
 Sacramento Municipal Utility District
 San Francisco, City and County of
 Sierra Pacific Power Company
 Turlock and Modesto Irrigation Districts
 U.S.W.P. - Mid Pacific Region
 Western Area Power Administration - Mid
 Pacific Region

Electric Region 24 - Rocky Mountain Power AreaHistorical Perspective

The Rocky Mountain Power Area (RMPA) encompasses the entire state of Colorado, the eastern half of Wyoming, and a portion of southwestern South Dakota.

Major utilities in the area include: Public Service Company of Colorado (PSCC) which serves more than 50 percent of area electric demand; D.O.E., Western Area Power Administration (WAPA) which serves various public utilities within (and outside) the area; Colorado-UTE Electric Association (CUEA); City of Colorado Springs (CCS); Tri-State Generation and Transmission Association (TSG&T); and Black Hills Power and Light Company (BHP&L) serving loads in eastern Wyoming and southwest South Dakota.

Coordinated operation within the area has been minimal in the past, basically limited to planning and emergency assistance. However, the Colorado utilities are now beginning to operate on a much more closely coordinated basis in conjunction with other members of the Inland Power Pool.

Historically, area load growth has been relatively high. Energy for load growth averaged 8.4 percent from 1960 through 1973, 7.7 percent from 1973 through 1976, and 5.9 percent from 1976 through 1979. Reasons for the continued high growth relative to most other areas of the WSCC include strong demographic growth and extensive conversion of irrigation pumping from natural gas to electricity.

Electric usage is nearly constant in winter and summer, and in recent years the area has experienced annual peaks during both seasons. PSCC's winter peak is presently growing at a faster rate than the summer peak because of increased use of electric heating.

Table 9A.1

Historical Load Growth
Rocky Mountain Power Area

	<u>1977</u>	<u>1978</u>	<u>1979</u>
Energy Load (Gwh)	24,367	25,923	27,718
Growth from Previous Year (%)	4.4	6.4	6.9
Peak Demand (MW)	4,518	4,606	4,857
Growth from Previous Year (%)	11.3	1.9	5.4
Load Factor (%)	61.2	64.2	65.1

The predominant type of generating capability in the area is the 2904 MW of coal-fired steam generation which represented 45.2 percent of total planned capability and 59.7 percent of total generation in 1979.

A significant amount of hydroelectric capability exists within the area totalling 35 percent of the planned capability and accounting for approximately 28 percent of the total area energy generation during average water conditions. The majority of this hydro

generation is owned and operated by the U.S. Water and Power Resources Service (formerly UBR) and marketed by WAPA's Upper Colorado and Lower Missouri Regions.

The only nuclear generating plant in the area is the 330 MW Fort St. Vrain high temperature gas reactor which was declared commercially operable at reduced power in January 1979. This PSCC owned facility originally produced energy in 1977 but technical problems resulted in the extended delay for commercial operation.

Seventeen percent of the area's planned capability is gas and/or oil fired which produced 11.7 percent of total electric energy generation in 1978. Consumption of these fuels for electricity production in 1979 was 832 thousand barrels of oil and 35.2 billion cubic feet of natural gas (5590 thousand equivalent oil barrels).

The area's utilities plan on the basis of a planned reserve margin of approximately 20 percent. Data for the past 3 years indicate that reserve margins have been sufficient.

Table 9A.2

Reserve Margins (%)
Rocky Mountain Power Area

	<u>1977</u>		<u>1978</u>		<u>1979</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u> (estimated)
Planned Reserves	32.4	41.3	26.1	29.3	24.2	26.3
Reservesg After Scheduled Maintenance	13.9	24.5	17.3	18.6	17.2	22.6
Actual Reserves	9.4	19.7	15.1	12.6	5.5	20.8

Table 9A.3
1979 Operation by Type of Plant
Rocky Mountain Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability (as of 12/31/79)</u>		<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> (X 1000)	
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	2070	32.2	7491	27.1		
Hydro Pumped Storage	Water	162	2.5	215	0.8		
Steam	Coal	2904	45.2	16499	59.7	9539	Tons
Steam	Oil			134	0.5	357	Barrels
Steam	Gas	374	5.8	2322	8.4	28247	MCF
Steam	Nuclear	200	3.1	183	0.7		
Combustion Turbine	Oil			198	0.7	448	Barrels
Combustion Turbine	Gas	667	10.4	553	2.0	6999	MCF
Internal Combustion	Oil	53 1/	0.8	15	0.1	27	Barrels
Total		6430	100.0	27610	100.0		

Total Fuel Consumption

Coal (tons x 1000)	9539
Gas (MCF x 1000)	35246
Gas (equivalent bbls x 1000)	5590
Oil: distillate (bbls x 1000)	528
residual	304
crude	0
Total Oil	832

1/ Natural Gas.

Table 9A.4
Historical Capability (MW) and Reserves (MW) and Percent)
Rocky Mountain Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	5981	5894	5808	6219	6030	6424
2. Peak Demand	4518	4170	4606	4810	4857	5085
3. Planned Reserves (1-2)	1463	1724	1200	1409	1173	1339
4. Planned Reserves (%) (3/2) x 100%	32.4	41.3	26.1	29.3	24.2	26.3
5. Net Transactions (Imports-Exports)	-729	-296	-285	-153	-308	-76
6. Total Capability (1+5)	5252	5598	5521	6066	5722	6348
7. Total Reserves (6-2)	734	1428	915	1256	865	1263
8. Total Reserves (%) (7/2) x 100%	16.2	34.2	19.9	26.1	17.8	24.8
9. Scheduled Maintenance	106	408	120	359	30	115
10. Capability After Maintenance (6-9)	5146	5190	5401	5707	5692	6233
11. Reserves After Maintenance (10-2)	628	1020	795	897	835	1148
12. Reserves After Maintenance (%) (11/2) x 100%	13.9	24.5	17.3	18.6	17.2	22.6
13. Inoperable Capability	202	200	100	290	570	92
14. Available Capability (10-13)	4944	4990	5301	5417	5122	6141
15. Available Reserves (14-2)	426	820	695	607	265	1056
16. Available Reserves (%) (15/2) x 100%	9.4	19.7	15.1	12.6	5.5	20.8
17. Forced Outages 1/	0	0	0	0	0	0
18. Actual Capability After Forced Outage (14-17)	4944	4990	5301	5417	5122	6141
19. Actual Reserves (18-2)	426	820	695	607	265	1056
20. Actual Reserves (%) (19/2) x 100%	9.4	19.7	15.1	12.6	5.5	20.8

XI.9.9

1/ Information not reported separately

Despite adequate reserve margins, reliability problems are substantial in the area as explained following.

Within the RMPA there are significant documented transmission bottlenecks which plague systems' reliability. Transmission limitations in western Colorado and southwestern Wyoming exist due to the delay of line additions needed to cover outage contingencies. These limitations coupled with generation shortages at individual utilities in the area have caused service disruptions and high risk situations on several occasions during the past few years. The bottlenecks also restrict transfers from outside the area and especially into the state of Colorado, a net energy importer. For example, the 1200 MW interconnection with the Arizona - New Mexico Power Area in southern Colorado is limited to 350 MW south to north because of transmission limitations internal to the Rocky Mountain Power Area.

Numerous transmission additions are under construction to alleviate many of the aforementioned limitations, but completion schedules have slipped due to various problems including regulatory requirements, labor force insufficiency, and project coordination.

Existing transmission in the area as of December 31, 1979 consists of: 5154 miles of 115kV; 2960 miles of 230 kV; and 181 miles of 345 kV. Interconnection to the east is limited to TSG&T's single 100 MW DC tie to the MARCA Region in Nebraska.

Current Perspective

Reserve margins in the Rocky Mountain Power Area (RMPA) are expected to be numerically well above requirements for 1980 as illustrated in the accompanying Table 9A.5. However, the aforementioned transmission deficiencies may cause reliability problems despite the scheduled addition of 77 miles of 115 kV line and 656 miles of 230 kV (operating voltage) line in 1980. Much of this construction is aimed specifically at relieving transmission overloads and improving reliability.

Prior to the forecasted summer peak only 187 miles of 230 Kv additions are scheduled to be in service. As a result, the west to east transfer capability within Colorado remains severely restricted and generator output in northwestern Colorado may also be restricted. Transfer capability into Colorado from either the north or the south also will likely remain insufficient through the summer peak period. No transmission exists westward to Utah.

Table 9A.5
Current Capability (MW) and Reserves (MW) and Percent) - 1980
Rocky Mountain Power Area

	Summer 1980			Winter 1980-81		
	June	July	August	December	January	February
1. Planned Capability <u>1/</u>	7320	7302	7285	7408	7878	7879
2. Peak Demand	4798	5297	5143	5150	5466	5116
3. Planned Reserves (1-2)	2522	2005	2142	2258	2410	2763
4. Planned Reserves (%) (3/2) x 100%	52.6	37.9	41.6	43.8	44.1	54.0
5. Net Transactions (Imports-Exports)	-444	-474	-458	-436	-562	-542
6. Total Capability (1+5)	6876	6828	6827	6972	7316	7337
7. Total Reserves (6-2)	2078	1531	1684	1822	1848	2221
8. Total Reserves (%) (7/2) x 100%	43.3	28.9	32.7	35.4	33.8	43.4
9. Scheduled Maintenance	376	0	230	395	65	293
10. Capability After Maintenance (6-9)	6500	6828	6597	6577	7251	7044
11. Reserves After Maintenance (10-2)	1702	1531	1454	1427	1783	1928
12. Reserves After Maintenance (%) (11/2) x 100%	35.5	28.9	28.3	27.7	32.6	37.7
13. Inoperable Capability	63	68	68	156	156	148
14. Available Capability (10-13)	6432	6760	6529	6421	7095	6896
15. Available Reserves (14-2)	1634	1463	1386	1271	1627	1780
16. Available Reserves (%) (15/2) x 100%	34.1	27.6	26.9	24.7	29.8	34.8
17. Forced Outages <u>2/</u>	289	273	115	102	111	190
18. Actual Capability After Forced Outage (14-17)	6143	6487	6414	6319	6984	6706
19. Actual Reserves (18-2)	1345	1190	1271	1169	1516	1598
20. Actual Reserves (%) (19/2) x 100%	28.0	22.5	24.7	22.7	27.7	31.1

1/ No delays anticipated in new generating units since submittal of 1980 ERA-411

2/ Three year historical average forced outage (1977-79)

Table 9A.6
Estimated 1980 Operation by Type of Plant
Rocky Mountain Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u>	<u>% of Total</u>	<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> (X 1000)	
		<u>MW</u>		<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	2142	29.3	7739	25.0		
Hydro Pumped Storage	Water	90	1.3	165	0.5		
Steam	Coal	3883	53.2	19557	63.0	11553	Tons
Steam	Oil			195	0.6	439	Barrels
Steam	Gas	381	5.2	2097	6.8	25922	MCF
Steam	Nuclear	200	2.7	706	2.3		
Combustion Turbine	Oil			201	0.7	422	Barrels
Combustion Turbine	Gas	553	7.6	350	1.1	4402	MCF
Internal Combustion	Oil	53 <u>1/</u>	0.7	11	0.0	22	Barrels
Total		7302	100.0	31021	100.0		

Total Fuel Consumption

Coal (tons x 1000)	11553
Gas (MCF x 1000)	30324
Gas (equivalent bbls x 1000)	4827
Oil: distillate (bbls x 1000)	444
residual	439
crude	0
Total Oil	883

1/ W Natural Gas.

XI.9.12

Load growth for the Region is forecast at 9.1 percent for peak demand from the actual summer of 1979 to that projected for the summer of 1980 and 8.6 percent in 1980 annual energy for load over 1979. These projects appear high, possibly due to mild weather conditions experienced in 1979 which may have contributed to less than usual energy usage.

During 1980, scheduled additions to generating capacity are significant and consist of 110 MW of coal-fired generation including: Unit No. 1 of the Laramie River Station (500 MW) which was undergoing testing as of April 1980; Ray D. Nixon Unit No. 1 (200 MW) which was placed into commercial operation on April 4, 1980; and Craig Unit No. 1 (400 MW) which remains on schedule for a June in-service date.

Future Perspective

Utilities in the Rocky Mountain Power Area (RMPA) forecast their combined annual peak demand to increase an average of 6.0 percent per year from 1980 through 1985 and 4.8 percent per year from 1985 through 1989. Energy growth is projected to increase 7.1 percent annually through 1985 and 5.4 percent from 1985 through 1989. These peak demand and energy growth rate projections are higher than those experienced during the past three years. Load factors are expected to increase from 62.8 percent in 1980 to 67.8 percent in 1989.

In addition to 110 MW of coal-fired generation expected to come on-line in 1980, 2190 MW are scheduled through 1985 and 2480 MW in 1986 through 1989. Coal fired capacity is expected to account for 75 percent of total area electric energy generation in 1985 and 80 percent in 1989 compared to 61.2 percent in 1978. Other additions include hydro and pumped storage plants. Table 9A.9 lists significant capacity additions scheduled for the Region.

Several major resource additions reported by the WSCC as of January 1, 1979 for the five year period have been rescheduled.

These units are tabulated below along with the current anticipated in-service date and the respective delay or acceleration with respect to the previously reported date.

Table 9A.7Scheduled Capability Additions that have been Delayed
Rocky Mountain Power Area

<u>Unit</u>	<u>Capacity (MW)</u>	<u>Previous Date</u>	<u>New Date</u>	<u>Delay (Months)</u>
Mount Elbert 1	100	10/79	7/18	19
Ray D. Nixon 1	200	12/79	4/80	4
Craig 1	400	12/79	6/80	6
Pawnee 1	470	7/80	1/81	6
Mount Elbert 2	100	4/81	8/83	28
Southeast 1	470	4/84	4/85	12
Rawhide 1	250	1/85	4/84	-9
Southeast 2	470	4/85	7/86	15
Osage 1	100	6/85	10/84	-8

Delays in bringing new coal-fired capability on-line in the area vary substantially from unit to unit. For example, the City of Colorado Spring's Ray D. Nixon Unit No. 1 which was originally scheduled for start-up in October 1979, actually became commercially operational in April 1980. Public Service Co. of Colorado's Pawnee Unit No. 1 which was originally scheduled for April 1979 and had slipped to July 1980 is now scheduled for January 1981, a 21 month delay which could further be extended.

Any energy shortages created by slippage of expected coal or hydro resources would result in increased imports of coal-fired generation (if available) and increased generation from existing area oil and gas fueled units. An estimate of additional oil/gas to replace delayed additions is difficult to calculate for this region.

The area presently has a total of 1067 MW of oil/gas fired generation consisting of steam, combustion turbine, and diesel units. No additions of these types of capability are planned. The primary fuel at most of the steam and combustion turbine units is natural gas. Estimated fuel consumption averages 4.1 million equivalent barrels of oil and natural gas over the next ten years. Increasing the annual capacity factor to 50 percent, under energy shortage conditions, would increase the gas/oil consumption to approximately 9.3 million equivalent barrels, or an additional 5.2 million equivalent barrels per year over the estimated consumption with no unit delays.

The Public Service Co. of Colorado is participating in the Western Utilities Coal-fired Plant Standardization Group and many of the planned coal-fired additions are standardized in design. Some of the expected benefits of the common design are reduced lead times, capital cost savings, increased availability, and operations savings.

Projected reserves are more than adequate based on timely additions to generating capability. Table 9A.8 summarizes expected reserves for the five years 1981 through 1985.

Table 9A.8

Projected Reserve Margins Winter (%)
Rocky Mountain Power Area

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Planned Reserves	44.7	43.6	43.6	42.2	40.4
Reserves after Scheduled Maintenance	25.3	25.4	27.0	28.2	29.6
Available Reserves	23.8	24.0	25.4	26.9	28.4

Based on the assumed delay of 6 months from the new schedule shown on Table 9A.9 for all coal-fired additions, available reserve margin shown below remain sufficient.

Table 9A.8a

Available Reserves Margins Winter (%)

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Delayed Schedule	23.8	24.0	19.4	25.5	28.4

Scheduled additions of transmission facilities from 1980 through 1989 consist of 101 miles of 115kV, 1424 miles of 230 kV, and 1101 miles of 345 kV line. These additions are designed to transport power from added generating units as well as eliminate existing transmission inadequacies. Continued delays in bringing these facilities into service, could result in a continuation of past reliability problems and possible additional consumption of natural gas and oil.

Table 9A.9

Significant Planned Additions to Generating Capability
Rocky Mountain Power Area

<u>Unit Name & No.</u>	<u>Type</u>	<u>Capacity</u> (MW)	<u>In Service Date</u>
Ray D. Nixon 1	Coal	200	4/80
Laramie R. Str. 1	Coal	500	4/80
Craig 1	Coal	400	6/80
Pawnee 1	Coal	470	1/81
Cabin Creek	Hydro	106	7/81
Mt. Elbert 1	Pumped Storage	100	7/81
Craig 3	Coal	400	7/83
Laramie R. Str. 3	Coal	500	4/82
Mt. Elbert 2	Pumped Storage	100	8/83
Rawhide 1	Coal	250	4/84
Osage 4	Coal	100	10/84
Southeast 1	Coal	470	4/85
Southeast 2	Coal	470	7/86
Pawnee 2	Coal	470	4/87
Ray D. Nixon 2	Coal	200	12/87
Unsited	Coal	470	4/88
Southwest 1	Coal	400	10/88
Glen Canyon 9-10	Hydro	250	12/88
Dominguez - 5	Pumped storage	500	12/88
Wyoming Coal 1	Coal	470	4/89
Flaming Gorge 4	Hydro	40	12/89
Diamond Fork Cup	Hydro	47.6	12/89

Table 9A.10.1
Future Capability (MW) and Reserves (MW and Percent) 1981/1984
Rocky Mountain Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	8324	8478	8838	9001	9272	9523	9633	9873
2. Peak Demand	5776	5857	6154	6268	6585	6631	6933	6941
3. Planned Reserves (1-2)	2548	2621	2684	2733	2687	2892	2700	2932
4. Planned Reserves (%) (3/2) x 100%	44.1	44.7	43.6	43.6	40.8	43.6	38.9	42.2
5. Net Transactions (Imports-Exports)	-941	-915	-960	-912	-953	-854	-896	-798
6. Total Capability (1+5)	7383	7563	7878	8089	8319	8669	8737	9075
7. Total Reserves (6-2)	1607	1706	1724	1821	1734	2038	1804	2134
8. Total Reserves (%) (7/2) x 100%	27.8	29.1	28.0	29.1	26.3	30.7	26.0	30.7
9. Scheduled Maintenance	0	223	68	228	0	247	0	178
10. Capability After Maintenance (6-9)	7383	7340	7810	7861	8319	8422	8737	8897
11. Reserves After Maintenance (10-2)	1607	1483	1656	1593	1734	1791	1804	1956
12. Reserves After Maintenance (%) (11/2) x 100%	27.8	25.3	26.9	25.4	26.3	27.0	26.0	28.2
13. Inoperable Capability	2	89	1	89	1	105	1	89
14. Available Capability (10-13)	7381	7251	7809	7772	8318	8317	8736	8808
15. Available Reserves (14-2)	1605	1394	1655	1504	1733	1686	1803	1867
16. Available Reserves (%) (15/2) x 100%	27.8	23.8	26.9	24.0	26.3	25.4	26.0	26.9
17. Forced Outages <u>2/</u>	-	-	-	-	-	-	-	-
18. Actual Capability After Forced Outage (14-17)	7381	7251	7809	7772	8318	8317	8736	8808
19. Actual Reserves (18-2)	1605	1394	1655	1504	1733	1686	1803	1867
20. Actual Reserves (%) (19/2) x 100%	27.8	23.8	26.9	24.0	26.3	25.4	26.0	26.9

XI.9.17

- 1/ No delays anticipated in new generating units since submittal of 1980 ERA-411
- 2/ Information on forced outage not available

Table 9A.10.2
Future Capability (MW) and Reserves (MW and Percent) 1985/1989
Rocky Mountain Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	10153	10293	10573	10768	10979	11318	11429	12538	12599	13254
2. Peak Demand	7292	7331	7650	7720	7982	8148	8370	8644	8831	8775
3. Planned Reserves (1-2)	2861	2962	2923	3048	2997	3170	3059	3894	3768	3379
4. Planned Reserves (%) (3/2) x 100%	39.2	40.4	38.2	39.5	37.5	38.9	36.5	45.0	42.7	51.0
5. Net Transactions (Imports-Exports)	-840	-791	-832	-783	-824	-775	-819	-770	-815	-785
6. Total Capability (1+5)	9313	9502	9741	9985	10155	10543	10610	11768	11784	12469
7. Total Reserves (6-2)	2021	2171	2091	2265	2173	2395	2240	3124	2953	3694
8. Total Reserves (%) (7/2) x 100%	27.7	29.6	27.3	29.3	27.2	29.4	26.8	36.1	33.4	42.1
9. Scheduled Maintenance 1/	-	-	-	-	-	-	-	-	-	-
10. Capability After Maintenance (6-9)	9313	9502	9741	9985	10155	10543	10610	11768	11784	12469
11. Reserves After Maintenance (10-2)	2021	2171	2091	2265	2173	2395	2240	3124	2953	3694
12. Reserves After Maintenance (%) (11/2) x 100%	27.7	29.6	27.3	29.3	27.2	29.4	26.8	36.1	33.4	42.1
13. Inoperable Capability	1	89	1	89	1	89	1	89	1	89
14. Available Capability (10-13)	9312	9413	9740	9896	10154	10454	10609	11679	11783	12380
15. Available Reserves (14-2)	2020	2082	2090	2176	2172	2306	2239	3035	2952	3605
16. Available Reserves (%) (15/2) x 100%	27.7	28.4	27.3	28.2	27.2	28.3	26.8	35.1	33.4	41.1
17. Forced Outages 1/	-	-	-	-	-	-	-	-	-	-
18. Actual Capability After Forced Outage (14-17)	9312	9413	9740	9896	10154	10454	10609	11679	11783	12380
19. Actual Reserves (18-2)	2020	2082	2090	2176	2172	2306	2239	3035	2952	3605
20. Actual Reserves (%) (19/2) x 100%	27.7	28.4	27.3	28.2	27.2	28.3	26.8	35.1	33.4	41.1

XI.9.18

1/ Information on scheduled maintenance and forced outages not available

Table 9A.11
Estimated 1985 Operation by Type of Plant
Rocky Mountain Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u>		<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> (X 1000)	
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	2199	22.1	7918	17.5		
Hydro Pumped Storage	Water	362	3.7	433	1.0		
Steam	Coal	6200	62.3	34178	75.5	20682	Tons
Steam	Oil	381	3.8	258	0.6	577	Barrels
Steam	Gas			1281	2.8	15375	MCF
Steam	Nuclear	200	2.0	701	1.5		
Combustion Turbine	Oil	553	5.6	221	0.5	511	Barrels
Combustion Turbine	Gas			274	0.6	3444	MCF
Internal Combustion	Oil	53 ^{1/}	0.5	10	0.0	20	Barrels
Total		9950	100.0	45274	100.0		
<u>Total Fuel Consumption</u>							
Coal (tons x 1000)		20682					
Gas (MCF x 1000)		18819					
Gas (equivalent bbls x 1000)		2988					
Oil: distillate (bbls x 1000)		777					
residual		331					
crude		0.1					
Total Oil		1108					

^{1/} 4MW Natural Gas.

Table 9A.12
Estimated 1989 Operation by Type of Plant
Rocky Mountain Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u>	<u>% of Total</u>	<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> (X 1000)	
		<u>MW</u>		<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	2522	20.3	5918	14.4		
Hydro Pumped Storage	Water	862	7.0	376	0.7		
Steam	Coal	7840	63.2	44295	80.8	27489	Tons
Steam	Oil			85	0.1	192	Barrels
Steam	Gas	364	2.9	1217	2.2	14548	MCF
Steam	Nuclear	200	1.6	701	1.3		
Combustion Turbine	Oil			147	0.3	298	Barrels
Combustion Turbine	Gas	553	4.6	94	0.2	1172	MCF
Internal Combustion	Oil	53 <u>1/</u>	0.4	9	0.0	18	Barrels
Total		12396	100.0	54840	100.0		

Total Fuel Consumption

Coal (tons x 1000)	27489
Gas (MCF x 1000)	15720
Gas (equivalent bbls x 1000)	2493
Oil: distillate (bbls x 1000)	356
residual	152
crude	0
Total Oil	508

1/ 4MW Natural Gas.

Electric Regions 25 and 30 - Northwest Power Pool AreaHistorical Perspective

The Northwest Power Pool Area (NWPP) includes 25 reporting systems which voluntarily operate on a coordinated basis. The pool area is comprised of the states of Washington, Oregon, Idaho, Utah, most of Montana and parts of Wyoming, Nevada and a small part of Northern California. Originally, the pool was divided into an East Group and West Group; however, increased interconnections between the two groups resulted in designation of the area as one entity. The Pacific Northwest Utilities Conference Committee (PNUCC), which is an outgrowth of the Northwest Power Pool, maintains the designation of West Group area. The PNUCC coordinates regional power planning and provides regional support for the Federal Marketing Agency for electric power by the U.S. Corps of Engineers and U.S. Water and Power Resources services (formerly U.S. Bureau of Reclamation).

The Northwest Power Pool Area has a pronounced winter peak that is heavily influenced by a significant saturation of electric heating loads. During the 1960's the area experienced an average annual growth rate of 6.9 percent. For the 1970-75 period the growth rates was about 3.8% which represents a substantial reduction from the 1960 decade. This reduction is generally attributed to a downturn of the economy, the 1973 oil embargo, and the 1973 drought, and resultant effects of customer conservation.

The conservation theme plus other load reduction efforts carried into the latter half of the 1970's resulted in a continuing lower growth rate. Since the area is heavily dependent on hydroelectric generation, power supply is very much affected by annual precipitation. In 1977, a serious drought occurred and in fact affected the entire WSCC area. Consequently, Northwest utilities curtailed secondary energy deliveries and issued appeals for voluntary customer curtailments of 10 percent. Additionally, procedures were adopted for mandatory curtailments in a four-state area. Because of hydroelectric generation deficiencies, the area imported significant amounts of energy to meet its load requirements. The drought ended in 1978 with a return to near normal water conditions. By fall of 1978, however, precipitation was again below normal in the Northwest resulting in lower than normal hydroreservoir storage entering the 1978-79 winter peak period. The effects of these water conditions are reflected in the growth rates for the 1977-79 period.

The below normal precipitation continued into 1979. On July 31, 1979, the date that Coordinated System reservoirs are programmed to refill, reservoir storage was only 90.7 percent of normally full contents, equivalent to 4.4 billion kilowatt hours of energy deficiency. During August the reservoirs deficiency increased to 5.4 billion kilowatt hours below normal.

Precipitation continued below normal during the remainder of 1979 creating a serious power supply situation for the 1979-80 water peak period.

No surplus hydro-generation was available from the Federal Columbia River Power System during the last half of 1979.

Actual load requirement data for the years 1977 through 1979 including annual growth rates and load factors are shown in the following table.

Table 9B.1

Historical Load Growth
Northwest Power Pool Area

	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy - Gwh	153,023	165,288	173,193
Growth Rate %	-1.5	8.0	4.8
Winter Peak Demand MW	25,584	31,495	32,021 ^{1/}
Growth Rate %	-4.0	23.1	1.7
Load Factor %	68.2	59.9	61.7

^{1/} Estimated for January 1980.

In 1979 hydroelectric generation supplied 70.3 percent of the total generation. Capability of oil and gas-fired steam-electric generating plants as of December 31, 1979 totaled only 316 MW or 0.8 percent of the total capacity. These plants are old and are used only for emergency peaking purposes. The sole combined cycle plant in the area is the 534 MW Beaver Plant installed in 1977 by Portland General Electric Company. The plant normally burns distillate oil but is capable of burning No. 4 oil. Facilities are now being installed at the Beaver Plant to accomodate use of natural gas. The lone coalfired generating plant in the West Group area is the two-unit 1300 MW Centralia Plant located in Centralia, Washington.

Presently, there is one nuclear generating plant operating in the Northwest: Trojan (1130 MW), operating by Portland General Electric Company (PGE). The Hanford, WA. Nuclear Power Reactor facility is not considered dependable capability for planning purposes.

The remainder of the Regions supply emanates primarily from East Group area coal-fired plants. Within the Regions, a total of 11.7 billion MCF of natural gas was burned in 1979 - equivalent to 1.9 million barrels of oil. Oil consumption was 1.64 million barrels.

Table 9B.7 shows operation by type of plant and fuel consumption for 1979.

Because of heavy dependency on hydroelectric generation a unique feature of the Northwest is that, during adverse water conditions, capability may be sufficient but energy supply can be simultaneously deficient. This was evident during the 1977 drought when the area imported large amounts of energy to meet load requirements but maintained sufficient capability margins.

Generally, high capacity reserve margins occur during the summer peak season. Excess summer capacity and associated energy serves secondary markets and interruptible loads. Historically, summer and winter capacity reserve margins have been more than adequate in the Northwest Power Pool Area.

Forced shutdown of the 1130 MW Trojan Nuclear Plant during the latter half of 1978, due to regulatory action, necessitated imports of oil fired energy from California and Canada. These imports resulted in a larger oil burn within the WSCC region than would have otherwise been required. Trojan was again shut down in October 1979 for maintenance and NRC required modifications. The loss of the Trojan plant coupled with below normal water conditions in the Northwest resulted in a very tight power supply situation for PGE entering the 1979-80 winter peaking season. The problem was alleviated somewhat when Trojan returned to service on December 31 and precipitation increased.

Table 9B.8 shows summer and winter peak loads, resources, and reserve margins for the years 1977 through 1979.

The Northwest Power Pool Area is a highly interconnected area. As of January 1, 1979, there were 38,900 circuit miles of transmission which represents 47% of the total transmission miles in the entire WSCC region. Bonneville Power Administration provides the electric power transmission network for marketing power for the Federal Columbia River Power System to major load centers of the Northwest. The BPA transmission system also serves as the backbone grid for all the Northwest utilities and covers a service area of some 300,000 square miles.

The lack of adequate east-west transmission across the Northwest Power Pool Area due principally to construction delays has frequently limited transfers of Montana and Wyoming area coal-fired generation to Pacific Coast load centers and has contributed to increased vulnerability of the interconnected system to major disturbances. A case in point was the major disturbance of November 27, 1979 when the Grand Coulee Power Plant lost 720 MW of generation. This loss of generation coupled with the scheduled outage of the 500 kV Pacific Northwest - Southwest Intertie resulted in conditions severe enough to cause islanding of the entire WSCC interconnected system. Construction has been chronically delayed on several major lines: notably the Colstrip, MT - Hot Springs, WY, double circuit 500 kV line; the Midpoint, ID - Malin, OR, 500 kV line; and the Kinport, ID - Midpoint, ID 345 kV line.

Northwest Power Pool Area is strongly interconnected to the Northern and Southern California Areas by three major transmission lines. Two of the lines are 500 kV (AC) with a total transfer capability of 2500 MW. The third is an 800 kV (DC) line with a capacity of 1440 MW. These interties are used to transmit surplus NWPP secondary energy to the south and southwest and for diversity exchange between the areas.

Current Perspective

For the 1980-81 winter peak season, requirements are estimated to increase by 9.9% for energy and 5.8% for peak load over that experienced during the 1979-80 winter season in the Northwest Power Pool area.

Since November 1979, adjusted monthly energy for loads have shown small amounts of growth over the previous year's corresponding monthly loads. December 1979 energy for load was 2 percent above the energy for load of December 1978 - 3.3 percent below forecast. Energy for loads for January, February and March 1980 increased by about 1 percent over the loads of corresponding

months of 1979. The annual growth rate had been consistently above five percent for several years preceding this period. This low growth in recent months is partly due to the curtailment of BPA's direct service industrial load. Other likely factors are a general economic slowdown and conservation effects.

Heavy precipitation was recorded in most of the Region during December 1979 and near normal water conditions continued through the first quarter of 1980. Reservoir storage at the end of March 1980 was very close to the level required for refill this summer. The outlook is for the area's reservoirs to be substantially full

by mid-August. However, performance of thermal generating plants, electric energy demands and upcoming fisheries operations in May will have major effects on the actual refill program. In any case, studies indicate there will be very little surplus hydro-generated energy available for non-firm loads, displacement of thermal generation, or export from the Northwest before next fall.

Capability additions scheduled in service for 1980 include 1,075 MW of hydroelectric, 930 MW of coal-fired and 178 MW of gas/oil fired generation. Utah Power & Light Company's Hunter No. 2 400 MW, and Portland General Electric Company's Boardman, 530 MW, both coalfired units, are scheduled for service in June and November, respectively. In November, Puget Sound Power & Light Company is planning to install two combustion turbine units totaling 178 MW which will burn either natural gas or distillate oil.

The Trojan nuclear plant was shut down April 11 for refueling and maintenance. Trojan is expected to return to service by summer 1980.

The following table shows the schedule in-service dates for major generating units during 1980.

Table 9B.2

Major Capability Additions in 1980
Northwest Power Pool Area

	<u>Type</u>	<u>Capability MW</u>	<u>In-Service Date</u>
Grand Coulee No. 24	Hydro	700	May 80
Hunter No. 2	Coal	400	Jun 80
Boardman	Coal	530	Nov 80

The Boardman plant in-service date is the probable energy date which is determined by the PNUCC from a standardized schedule reflecting anticipated average planning and construction times. The estimated commercial operation date is July 1980.

Estimated operation by type of plant and fuel use under median hydro conditions (energy) is shown in Table 9B.9.

For reserve study purposes the U.S. portion of the Northwest Power Pool Area is assumed to be an infinite bus. Present transfer capability between the East Group and West Group is limited to an extent which may limit transfer of energy to the West Group area.

Anticipated available and planned reserve margins for the 1980 winter peaking season appear sufficient based on WSCC's "Power Supply Design Criteria," criterion 1 and the Pacific Northwest Coordination Agreement Method (LOLP - one day in 20 years), but not the PNUCC West Group Criterion 1(b) (13 percent of firm peak load). Reserve margins shown in Table 9B.10 are much lower than those listed prior to last year. This reduction is due to BPA changing the representation of the Federal hydro capability from a one hour peak to a ten hour sustained peaking capability. Grand Coulee hydro capability has been reduced by 1543 MW through the summer of 1983 due to a tailwater problem. Also, it should be noted that in Table 9B.10, dependable capability includes hydro resources based on adverse water conditions. It is difficult to obtain median or average water condition ratings for hydro plants; however, it is known that, based on magnitudes of scale, dependable hydro capability based on median conditions is less than five percent above those rated on adverse conditions.

Future Perspective

The Northwest Power Pool Area loads are projected to increase in the five-year period from 1980-85 at an average annual rate of 4.4 percent for winter peak demand and 4.5 percent for annual energy use. This energy growth rate is somewhat higher than the 3.7 percent experienced during the 1977-79 period when below normal water conditions occurred twice in three years.

For the years 1985 through 1989 peak demand average annual growth rate is forecast at 2.8 percent while energy use is estimated to increase at a 3.5 percent average annual rate.

Although growth rates are declining, total growth nevertheless is forecasted to be substantial. Energy use is estimated to increase from 173,193 GWh in 1979 to 272,025 GWh in 1989. Peak demand is forecast to increase from 32,021 MW to 46,378 MW during that same period.

Additions to generating capacity for the Regions total 7,056 MW for the period 1981 through 1985. Table 9B.3 lists the significant units by type and delays of in-service dates.

Table 9B.3

Scheduled Capability Additions
Northwest Power Pool Area

<u>Generating Unit</u>	<u>Type</u>	<u>MW Capability</u>	<u>In-Service Date</u>		<u>Total Delay (Months)</u>
			<u>Original</u>	<u>Current</u>	
WNP 2	Nuclear	1100	3/78	1/83 <u>1/</u>	58
Hunter 3	Coal	400		6/83	
Colstrip 3	Coal	700	7/78	1/84	66
WNP 1	Nuclear	1250	9/80	6/85 <u>1/</u>	57
Junter 4	Coal	400		6/85	
Colstrip 4	Coal	700	7/79	9/85	64
WNP 3	Nuclear	1240		6/86 <u>1/</u>	

1/ Revised from 1980 ERA-411 by Washington
Public Power Supply System

Significant additions include 2200 MW of coal-fired and 3,590 MW of nuclear units. Current in-service dates are "Probable PNUCC Energy Dates" using the Milestone procedure based on critical path analysis methods. The milestone procedure reflects the possible plant delays in excess of those considered in scheduled commercial operation dates.

As shown in the Table 9B.3, significant delays have occurred since conception for four major plants. Even since the report of April 1, 1979, one year ago, there have been several delays. Units affected and the months of delay since last year's report are listed in Table 9B.4.

Table 9B.4

Unit Delays from 3/79 - 3/80
Northwest Power Pool Area

<u>Generating Unit</u>	<u>In-Service Date</u>		<u>Delay (Mo.)</u>
	<u>April 1, 1979</u>	<u>Current</u>	
Colstrip 3	3/83	1/84	6
Colstrip 4	3/85	9/85	6
Boardman	7/80	11/80	4
WNP 1	12/83	6/85 1/	18
WNP 2	9/81	1/83 <u>I</u> /	16

1/ Revised from 1980 ERA-411 by Washington
 Public Power Supply System.

For the period 1986 through 1990 a total of 8,908 MW is planned for addition to the Regions' capability. Significant unit additions for this period are listed by type in Table 9B.5.

Table 9B.5

Major Capability Additions 1986 - 1990
Northwest Power Pool Area

<u>Generating Unit</u>	<u>Type</u>	<u>Net Capability</u>	<u>Schedule in Service</u>
		<u>MW</u>	<u>Date</u>
WNP 4	Nuclear	1250	6/86 1/
WNP 5	Nuclear	1240	6/87 <u>I</u> /
Intermountain 1	Coal	750	7/86
Intermountain 2	Coal	750	7/87
Wellington 1	Coal	500	6/88
Intermountain 3	Coal	750	7/88
Intermountain 4	Coal	750	7/89
Skagit 1	Nuclear	1285	7/90

1/ Revised from 1980 ERA-411 by Washington
 Public Power Supply System.

Intermountain coal plant is a joint project: forty-two percent of the project's output will be shared by Utah utilities and the remainder will be transmitted to southern California utilities.

There are also 453 MW of combustion turbine generation planned for installation during the 1981-89 period. Of this amount, 178 MW is specified to use distillate oil as the primary fuel.

Tables 9 B.13 and 9 B.14 show the estimated operation by type of plant and fuel use for the years 1985 and 1989. Under median hydro conditions estimated oil/gas-fired generation will supply 0.9 percent of the total generation in 1985 and 0.6 percent in 1989.

The PNUCC "West Group Forecast" reports that nearly every unit of planned resources for the West Group area is behind schedule by three years since the 1977 forecast. A noteworthy change in its latest forecast is the planned deferrals of two unlicensed nuclear plants: Skagit and Pebble Springs. Only Skagit unit No. 1, now scheduled for July 1990, is shown in the current PNUCC forecast.

Presently, Colstrip Unit Nos. 3 and 4 are on schedule but in-service dates of WNP 1 and 2 are being reviewed. Delays in unit installations have produced only small peak deficiencies to date; however, peak demand reserve margins are projected to decrease and energy deficits are projected to increase significantly with each additional unit delay.

The estimated reserve margins for the Northwest Power Pool Area are indicated in Table 9B.12.1 and 9B.12.2. During the period July 1981 through June 1983 the Pool does not meet WSCC criteria 1 for desired reserve margins. It should be noted that BPA, for planning purposes, includes approximately 1000 MW of interruptible loads in its firm load. If these interruptible loads were to be used for reserve, there could be sufficient reserve margin for the entire ten-year period. Also, for this forecast, hydro resource capabilities are estimated on an adverse water year basis.

Reserve requirements vary considerably depending on the criteria used. WSCC reliability criteria is defined on Table 9 B.11. The Pacific Northwest Coordination Agreement reserve criteria provides for capability reserves based on a loss of load probability of one day in 20 years. The most stringent requirements are those of the

West Group which basically requires a reserve margin of twelve percent of firm peak load the first year, increasing one percent per year to twenty percent, and remaining at twenty percent thereafter. The West Group reliability criteria indicates deficiencies in reserve margin for the entire period through June 1984.

Since the Pool Area is basically a hydro oriented system energy resources are important in assessing the forecasted load-supply situation.

Studies conducted in conjunction with the West Group Forecast indicate there is a probability that the resources in the western portion of the Pool will be insufficient to meet total energy load under adverse water conditions during the ten year forecast period.

In addition, for purposes of this report, a delay of 6 months was assumed for the major coal plants, shown in Table 9B.3.

Table 9B.6 shows the affects on reserve margins of nuclear plants' delays and an assumed 6 months delay in specified coal plant units.

Table 9B.6

Estimated Available Reserve Margins (%)
Northwest Power Pool Area
Winter Peak Period

	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
			<u>- Percent -</u>			
Present Schedule	7.7	6.2	5.0	8.8	9.7	15.3
Delayed Schedule	7.7	6.2	5.0	8.8	6.6	10.7

There are three critical bulk power transmission facilities that will not be in service when desired. A discussion of each line and its effects on the bulk power system follows.

The Kinport, ID - Midpoint, ID 345 kV line is to be constructed, owned and operated by Idaho Power Company (IPC) to permit transfer of Wyoming resources through IPC's service area. This line was scheduled for service concurrent with the start-up of Jim Bridger Unit 4 in December 1979, but has now been delayed to October 1981 due to delays in obtaining necessary construction permits.

Pacific Power and Light Company's (PP&L) Midpoint, ID - Malin - Medford, OR 500 kv line will serve as an interconnection between IPC and PP&L. The line represents a critical link in the transmission system that is being constructed in cooperation with IPC to permit transfer of PP&L's Wyoming resources to the West Group area. In addition, the proposed line is purportedly required to reinforce the bulk power supply to PP&L's Southern Oregon load area.

It is estimated that the 445 mile Malin-Midpoint section of the line will be delayed approximately three years from the originally scheduled in-service date of October 1978. Final Federal permits were received in October and construction of the line was started in December 1979. The completion date is now scheduled for September 1981. As a result of this delay West Group area deficiencies will be increased by up to 900 MW of capability and 400 MW of average energy.

The Montana Power Company's Bozeman-Dillion 161 kv line and associated facilities were scheduled for November 1978. The line has been postponed pending resolution of a law suit relating to environmental concerns. This delay adversely affects the reliability of service in the Dillion, MT area.

Table 9B.7
1979 Operation by Type of Plant
Northwest Power Pool Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u> <u>(as of 12/31/79)</u>		<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> <u>(x 1000)</u>	
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	30753	75.0	125503	70.3	-	
Hydro Pumped Storage	Water	100	0.2	0	-	-	
Steam	Coal	7498	18.3	41860	23.4	24874	Tons
Steam	Oil	316	0.8	303	0.2	642	Barrels
Steam	Gas			581	0.3	6968	MCF
Steam	Nuclear	1080	2.6	8634	4.8		
Combustion Turbine	Oil	637	1.6	20	-	46	Barrels
Combustion Turbine	Gas			385	0.2	4713	MCF
Combined Cycle	Oil	534	1.3	577	0.3	952	Barrels
Combined Cycle	Gas			0			
Geothermal	GST	-					
Internal Combustion	Oil	33	0.1	0			
Fuel Cell	---	---					
Other		<u>70</u>	<u>0.2</u>	<u>705</u>	<u>0.4</u>		
Total		41021	100.0	178568	100.0		
<u>Total Fuel Consumption</u>							
Coal (tons x 1000)		24874					
Gas (MCF x 1000)		11681					
Gas (equivalent bbls x 1000)		1904					
Oil: distillate (bbls x 1000)		998					
residual		642					
crude		0					
Total Oil		1646					

Table 9B.8

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Northwest Power Pool Area

	1977		1978		1979	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability <u>1/</u>	34694	34280	37859	39784	39169	37641
2. Peak Demand	20501	25584	22283	31495	23014	32021
3. Planned Reserves (1-2)	14193	8696	15576	8289	16155	5620
4. Planned Reserves (%) (3/2)x100	69.2	34.0	69.9	26.3	70.2	17.6
5. Net Transactions (Imports-Exports)	-3135	-1655	-3281	-1747	-3075	-1730
6. Total Capability (1+5)	31559	32625	34578	38037	36094	35911
7. Total Reserves (6-2)	11058	7041	12295	6542	13080	3890
8. Total Reserves (%) (7/2)x100	53.9	27.5	55.2	20.8	56.8	12.1
9. Scheduled Maintenance	7051	2602	5136	4689	7398	776
10. Capability after Maintenance (6-9)	24508	30023	29442	33348	28696	35135
11. Reserves after Maintenance (10-2)	4007	4439	7159	1853	5682	3114
12. Reserves after Maintenance (%) (11/2)x100	19.5	17.4	32.1	5.9	24.7	9.7
13. Inoperable Capability	0	100	0	130	30	167
14. Available Capability (10-13)	24508	29923	29442	33218	28666	34968
15. Available Reserves (14-2)	4007	4339	7159	1723	5652	2947
16. Available Reserves (%) (15/2)x100	19.5	17.0	32.1	5.5	24.6	9.2
17. Forced Outages <u>2/</u>	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	24508	29923	29442	33218	28666	34968
19. Actual Reserves (18-2)	4007	4339	7159	1723	5652	2947
20. Actual Reserves (%) (19/2)x100	19.5	17.0	32.1	5.5	24.6	9.2

1/ Excludes Canadian Systems.

2/ Information not reported separately.

Table 9B.9
Estimated 1980 Operation by Type of Plant
Northwest Power Pool Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u> <u>(as of 2/31/80)</u>		<u>Annual Energy</u> <u>1/</u>		<u>Fossil</u>
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>	<u>Fuel</u> <u>Consumption</u> <u>(x 1000)</u>
Hydro	Water	27373	72.7	140589	73.4	-
Hydro Pumped Storage	Water	100	0.3	-	-	-
Steam	Coal	7498	19.9	40031	20.9	23104 Tons
Steam	Oil	316	0.8	-	-	-
Steam	Gas	-	-	244	0.1	3235 MCF
Steam	Nuclear	1080	2.9	13555	5.5	-
Combustion Turbine	Oil	637	1.7	-	-	-
Combustion Turbine	Gas	-	-	112	0.1	1562 MCF
Combined Cycle	Oil	534	1.4	0	-	-
Combined Cycle	Gas	-	-	0	-	-
Geothermal	GST	-	-	-	-	-
Internal Combustion	Oil	33	0.1	0	-	-
Fuel Cell	-	-	-	-	-	-
Other		70	0.2	-	-	-
Total		37641	100.0	191531	100.0	-
<u>Total Fuel Consumption</u>						
Coal (tons x 1000)		23104				
Gas (MCF x 1000)		4797				
Gas (equivalent bbls x 1000)		785				
Oil: distillate (bbls x 1000)		-				
residual		-				
crude		-				
Total Oil		0				

1/ Median Hydro Conditions.

Table 9B.10

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent) - 1980/81
Northwest Power Pool Area

	Summer 1980			Winter 1980/81		
	Dec	Jan	Feb	Dec	Jan	Feb
1. Planned Capability <u>1/</u>	36611	38241	38238	39351	39059	38534
2. Peak Demand <u>2/</u>	26010	25898	25550	32801	33888	32147
3. Planned Reserves (1-2)	12601	12343	12688	6550	5171	6387
4. Planned Reserves (%) (3/2)x100	48.4	47.7	49.7	20.0	15.3	19.9
5. Net Transactions (Imports-Exports)	-2956	-2939	-2954	-1585	-1605	-1622
6. Total Capability (1+5)	35655	35302	35284	37766	37454	36912
7. Total Reserves (6-2)	9645	9404	9734	4965	3566	4765
8. Total Reserves (%) (7/2)x100	37.1	36.3	38.1	15.1	10.5	14.8
9. Scheduled Maintenance	2633	3058	3192	988	781	894
10. Capability after Maintenance (6-9)	33022	32244	32092	36778	36673	36018
11. Reserves after Maintenance (10-2)	7012	6346	6542	3977	2785	3871
12. Reserves after Maintenance (%) (11/2)x100	27.0	24.5	25.6	12.1	8.2	12.0
13. Inoperable Capability	167	167	167	167	167	167
14. Available Capability (10-13)	32855	32077	31925	36611	36506	35851
15. Available Reserves (14-2)	6845	6179	6375	3810	2618	3704
16. Available Reserves (%) (15/2)x100	26.3	23.9	25.0	11.6	7.7	11.5
17. Forced Outages <u>3/</u>	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	32855	32077	31925	36611	36506	35851
19. Actual Reserves (18-2)	6845	6179	6375	3810	2618	3704
20. Actual Reserves (%) (19/2)x100	26.3	23.9	25.0	11.6	7.7	11.5

1/ No delays anticipated in new generating units since submittal of 1980 ERA-411.

2/ Includes 461 MW of interruptible capability.

3/ Information not available.

Table 9B.11

WSCC Power Supply Design Criteria
Recommended Minimum Performance Table
Northwest Power Pool Area

It is recommended that areas or systems defined for analysis should meet or exceed at least one of the following WSCC criteria for installed and planned generating capacity:

<u>Criteria</u>	<u>Minimum Design Performance</u>
1. Monthly Reserve Capability After Deducting Scheduled Maintenance (MW)	Greater of R, or the largest Risk plus 5% of Load Responsibility
2. Monthly Reserve Capability After Deducting Scheduled Maintenance	2 largest Risks
3. Annual reliability criterion based on probability of loss of load, either	
a. Frequency of loss of load or,	1 day in 10 years
b. probability of meeting all loads in a year	0.90

Definitions

$$R = \left(\frac{.05 H + .15 T}{H + T} \right) \times L$$

H = Monthly hydro capability after deducting scheduled maintenance.

T = Monthly thermal capability after deducting scheduled maintenance.

L - Load Responsibility: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier.

Reserve Capability after Deducting Scheduled Maintenance = H + T - L

Risk: Capability reduction caused by outage of a generator or transmission line.

Performance Table Adopted by Executive Committee - September 19, 1974.

Table 9B.12.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Northwest Power Pool Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	39464	39750	41171	41151	41679	44277	44175	46344
2. Peak Demand ^{1/}	27269	35449	28303	37181	29760	38843	30875	40404
3. Planned Reserves (1-2)	12195	4301	12868	3970	11919	5434	13300	5940
4. Planned Reserves (%) (3/2)x100	44.7	12.1	45.5	10.7	40.1	14.0	43.1	14.7
5. Net Transactions (Imports-Exports)	-3135	-1136	-2389	-1139	-2242	-1058	-2371	-1046
6. Total Capability (1+5)	36329	38614	38782	40012	39437	43219	41804	45298
7. Total Reserves (6-2)	9060	3165	10479	2831	9677	4376	10929	4894
8. Total Reserves (%) (7/2)x100	33.2	8.9	37.0	7.6	32.5	11.3	35.4	12.1
9. Scheduled Maintenance	3951	788	3819	793	3986	803	4698	804
10. Capability after Maintenance (6-9)	32378	37826	34963	39219	35451	42416	37106	44494
11. Reserves after Maintenance (10-2)	5109	2377	6660	2038	5691	3573	6231	4090
12. Reserves after Maintenance (%) (11/2)x100	18.7	6.7	23.5	5.5	19.1	9.2	20.2	10.1
13. Inoperable Capability	167	167	167	167	167	167	167	167
14. Available Capability (10-13)	32211	37659	34796	39052	35284	42249	36939	44327
15. Available Reserves (14-2)	4942	2210	6493	1871	5524	3406	6064	3923
16. Available Reserves (%) (15/2)x100	18.1	6.2	22.9	5.0	18.6	8.8	19.6	9.7
17. Forced Outages ^{2/}	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	32211	37659	34796	39052	35284	42249	36939	44327
19. Actual Reserves (18-2)	4942	2210	6493	1871	5524	3406	6064	3923
20. Actual Reserves (%) (19/2)x100	18.1	6.2	22.9	5.0	18.6	8.8	19.6	9.7

Nuclear Unit Delays as Projected by Utilities

21. Nuclear Delays ^{3/}	0	0	1100	0	0	0	0	1250
22. Actual Capability (18-21)	32211	37659	33696	39052	35284	42249	36939	43077
23. Actual Reserves with Nuclear Delays (22-2)	4942	2210	5393	1871	5524	3406	6064	2673
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	18.1	6.2	19.1	5.0	18.6	8.8	19.6	6.6

^{1/} Includes 461 MW of interruptible load.

^{2/} Information not available.

^{3/} Washington Public Power Supply System update of 1980 ERA-411.

Table 9B.12.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Northwest Power Pool Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	46447	49465	49166	50788	50540	51030	51345	51697	51431	53548
2. Peak Demand 1/	32079	41893	33165	43403	34219	44975	35343	46534	36486	46765
3. Planned Reserves (1-2)	14368	7572	16001	7385	16321	6055	16002	5163	14945	6783
4. Planned Reserves (%) (3/2)x100	44.8	18.1	48.2	17.0	47.7	13.5	45.3	11.1	41.0	14.5
5. Net Transactions (Imports-Exports)	-2237	-988	-2178	-35	-646	900	247	1324	671	1654
6. Total Capability (1+5)	44210	48477	46988	50753	49894	51930	51592	53021	52101	55202
7. Total Reserves (6-2)	12131	6584	13823	7350	15675	6955	16249	6487	15616	8437
8. Total Reserves (%) (7/2)x100	37.8	15.7	41.7	15.9	45.8	15.5	46	13.9	42.8	18.0
9. Scheduled Maintenance 2/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	44210	48477	46988	50753	49894	51930	51592	53021	52102	55202
11. Reserves after Maintenance (10-2)	1213	6584	13823	7350	15675	6955	16249	6487	15616	8437
12. Reserves after Maintenance (%) (11/2)x100	37.8	15.7	41.7	15.9	45.8	15.5	46.0	13.9	42.8	18.0
13. Inoperable Capability	167	167	167	167	167	167	167	167	167	167
14. Available Capability (10-13)	44043	48310	46821	50586	49727	51763	51425	52854	51935	55035
15. Available Reserves (14-2)	11964	6417	13656	7183	15508	6788	16082	6320	15449	8270
16. Available Reserves (%) (15/2)x100	37.3	15.3	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7
17. Forced Outages 2/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	44043	48310	46821	50586	49727	51763	51425	52854	51935	55035
19. Actual Reserves (18-2)	11964	6417	13656	7183	15508	6788	16082	6320	15449	8270
20. Actual Reserves (%) (19/2)x100	37.3	15.3	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7

Nuclear Unit Delays as Projected by Utilities

21. Nuclear Delays 3/	0	1240	0	0	0	0	0	0	0	0
22. Actual Capability (18-21)	44043	47070	46821	50586	49727	51763	51425	52854	51935	55035
23. Actual Reserves with Nuclear Delays (22-2)	11964	5177	13656	7183	15508	6788	16082	6320	15449	8270
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	37.3	12.4	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7

1/ Includes 461 MW (Summer 1985) and 387 MW all other periods of interruptible load.

2/ Information on scheduled maintenance and forced outages not available.

3/ Washington Public Power Supply System update of 1980 ERA-411.

Table 9B.13
Estimated 1985 Operation by Type of Plant
Northwest Power Pool Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u> <u>(as of 1/1/85)</u>		<u>Annual Energy</u> <u>1/</u>		<u>Fossil</u> <u>Fuel</u> <u>Consumption</u> <u>(x 1000)</u>
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>	
Hydro	Water	30366	65.4	141465	60.4	-
Hydro Pumped Storage	Water	300	0.6	0	-	
Steam	Coal	10380	22.4	69236	29.5	35002 Tons
Steam	Oil	316	0.7	-		
Steam	Gas			245	0.1	3235 MCF
Steam	Nuclear	3400	7.3	21409	9.1	
Combustion Turbine	Oil	993	2.1			
Combustion Turbine	Gas			245	0.1	3035 MCF
Combined Cycle	Oil	534	1.2	1707	0.7	2875 Barrels
Combined Cycle	Gas					
Geothermal	GST					
Internal Combustion	Oil	33	0.1			
Fuel Cell						
Other		<u>112</u>	<u>0.2</u>	<u> </u>	<u> </u>	
Total		46434	100.0	234307	100.0	
<u>Total Fuel Consumption</u>						
	Coal (tons x 1000)	39637				
	Gas (MCF x 1000)	6260				
	Gas (equivalent bbls x 1000)	1025				
	Oil: distillate (bbls x 1000)	2875				
	residual					
	crude					
	Total Oil	2875				

1/ Energy estimated for median hydro conditions.

Table 9B.14
Estimated 1989 Operation by Type of Plant
Northwest Power Pool Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u> (as of 1/1/89)		<u>Annual Energy</u> ^{1/}		<u>Fossil Fuel Consumption</u> (x 1000)
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>	
Hydro	Water	30709	58.1	142876	52.4	
Hydro Pumped Storage	Water	300	0.6	0		
Steam	Coal	12352	23.4	82053	30.1	45586 Tons
Steam	Oil	316	0.6	0		
Steam	Gas			245	0.1	3238 MCF
Steam	Nuclear	7160	13.5	46367	17.0	
Combustion Turbine	Oil	1343	2.5	0	-	46 Barrels
Combustion Turbine	Gas			245	0.1	3035 MCF
Combined Cycle	Oil	534	1.0	1127	0.4	1898 Barrels
Combined Cycle	Gas					
Geothermal	GST	-				
Internal Combustion	Oil	33	0.1			
Fuel Cell	-	-				
Other		<u>112</u>	<u>0.2</u>	<u> </u>	<u> </u>	
Total		52859	100.0	272913	100.0	
<u>Total Fuel Consumption</u>						
	Coal (tons x 1000)	45586				
	Gas (MCF x 1000)	6237				
	Gas (equivalent bbls x 1000)	1027				
	Oil: distillate (bbls x 1000)	1898				
	residual					
	crude					
	Total Oil	1898				

1/ Energy estimated for median hydro conditions.

Electric Region 26 Arizona - New Mexico Power AreaHistorical Perspective

Arizona-New Mexico Power Area (AZ-NM) encompasses Arizona, most of New Mexico, and small portions of southeast California and northwestern Texas. The Region is served by 49 utility systems.

The summer peaking region historically was a high growth area in terms of peak demand and energy. During the 1960's decade, the average annual growth rate was approximately 8 percent for peak and 7.6 percent for energy. This growth rate continued in the early 1970's when the average annual growth rate for the five year period 1970 through 1975 was about 7.6 percent for peak and 7.1 percent for energy. These energy growth rates have decreased considerably during the last half of the 1970's. Average annual growth rate for the years 1977 through 1979 was 5.4 percent for energy use and 4.5 percent for peak demand. Actual loads data for 1977 through 1979 are shown on Table 9C.1.

Table 9C.1

Historical Load Growth
Arizona-New Mexico Area

	<u>1977</u>	<u>1978</u>	<u>1979</u>
Annual Electric Energy (GWh)	35787	37387	39734
Growth Rate %	5.2	4.5	6.3
Summer Peak Demand (MW)	7266	7942	7942
Growth Rate %	3.3	9.3	0.0
Load Factor %	56.2	53.7	57.1

The Region's peak demand for 1979 was equal to that experienced in 1978. This is attributed to the mild weather that was prevalent during the summer and fall of 1979.

The major portion of the area's generation emanates from coal-fired generating plants which supplied 60.4 percent of the Region's total generation in 1979. About 32 percent of the total Regional generation was from oil/gas-fired power plants. For 1979, natural gas consumption amounted to 104.3 million MCF, equivalent to 17.4 million barrels of oil.

Two major additions were made to the Region's coal-fired generating capability during 1979. The 480 MW San Juan unit No.3 and the first of three units of the Coronado project (350 MW ea) were put into service the latter part of the year.

Operation by type of plant and fuel consumption for 1979 is shown in Table 9C.2.

During December 1978 and January 1979, the area experienced one of the coldest winters on record. Sub-normal temperatures caused higher than anticipated loads and forced outages of numerous coal-fired generating units. As a consequence, oil inventories were minimal through the Southwest at the end of 1978. Emergency assistance was provided by California utilities to the AZ-NM Region.

Table 9C.11 shows reserves for summer and winter peak months for the years 1977 through 1979. During this period, actual reserve margins have equalled or exceeded 15 percent of the region's peak demand except for the unusual 1978 winter season when the available reserve dropped to 8.3 percent.

As of January 1980, the AZ-NM transmission system included 3930 miles of 115-161 kV, 1900 miles of 230 kV, 2859 miles of 287-345 kV and 1340 miles of 500 kV lines. Interconnections with the Southern California - Nevada Power area (Electric Region 27) consist of two 500 kV, one 287 kV and five 230 kV tie lines. The two 500 kV lines transfer other Regional utility shares of power output from the Navajo and Four Corners power plants. Interregional transfer capability is 2300 MW from east to west.

An interconnection to the Northwest Power Pool, East Group area (Region 30), is through a 345 kV line from the Four Corners plant. This interconnection is considered adequate with its 600 MW rated transfer capability.

Interconnections between the Rocky Mountain Power Area (Electric Region 24) consist of one 230 kV line and two 345 kV lines. Transfer capability is 1200 MW north to south and 350 MW south to north. The lower transfer limit from south to north is restricted by transmission limitations within the Rocky Mountain area.

Table 9C.2

1979 Operation by Type of Plant
Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of 12/31/79)		Annual Energy		Fossil Fuel Consumption (x 1000)	
		MW	% of Total	Gwh	% of Total		
Hydro	Water	6063	5.6	3008	7.4		
Hydro Pumped Storage	Water	137	1.3	0			
Steam	Coal	4957	46.0	24618	60.4	13136	Tons
Steam	Oil	2845	26.4	3330	8.2	5798	Barrels
Steam	Gas	-		7034	17.3	79945	MCF
Steam	Nuclear	0		0		0	
Combustion Turbine	Oil	1389	12.9	101	0.2	307	Barrels
Combustion Turbine	Gas	-		698	1.7	9463	MCF
Combined Cycle	Oil	834	7.7	403	1.0	771	Barrels
Combined Cycle	Gas			1540	3.8	14829	MCF
Geothermal	GST	0					0
Internal Combustion	Oil	15	0.1	-			0
Fuel Cell	-						
Other		70	0.2	705	0.4		
Total		10783	100.0	407328	100.0		
<u>Total Fuel Consumption</u>							
Coal (tons x 1000)		13136					
Gas (MCF x 1000)		104258					
Gas (equivalent bbls x 1000)		17367					
Oil: distillate (bbls x 1000)		935					
residual		5941					
crude		0					
Total Oil		6876					

Current Perspective

The 1980 forecast for the Arizona - New Mexico Power Area estimated electric energy consumption will increase from 39,734 GWh in 1979 to 43,732 GWh in 1980, representing an increase of 10.1 percent. Summer peak demand is estimated to increase by 10.3 percent over 1979. However, because of a mild summer experienced in 1979, the average annual growth rate over the two year period from 1978 is expected to be 5 percent for the peak demand. The energy growth estimate appears high for 1980 when considering that the previous three years' increase averaged only 5.4 percent.

During 1980, 679 MW of generating capability is planned to be added to the regions' supply. Major additions include two coal-fired units totaling 592 MW. The two units are listed in Table 9C.3.

Table 9C.3

Additional Capability-1980
Arizona - New Mexico Power Area

<u>Unit & No.</u>	<u>Capabilty</u>	<u>Scheduled In-Service Date</u>
Cholla 3	242	Aug. 1980
Coronado 2	350	Oct. 1980

It is not likely that these units will be available for the opening summer peak season. Salt River Project will share 30 percent of the Coronado projects' output with Los Angeles Department of Water and Power (LADWP) until May 1983. At that time LADWP will commence receiving its share of Palo Verde Unit 1.

Two units (98 MW) of combustion turbines are being installed for the summer peak season. The units will have the capability of burning distillate oil or natural gas.

The 1980 estimated operation by type of plant and fuel consumption for the Region is shown in Table 9C.4.

Table 9C.12 indicates the reserve margins expected for 1980. More than adequate reserve margins are projected for the summer peak season when the annual peak occurs.

The bulk power transfer capability between the Arizona - New Mexico and adjacent regions is considered adequate for planned transfers. Presently there are no internal transmission limitations in the Region which would limit transfer capabilities or degrade adequacy.

Table 9C.4
Estimated 1980 Operation by Type of Plant
Arizona - New Mexico Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability (as of 07/80)</u>		<u>Annual Energy</u>		<u>Fossil Fuel Consumption</u> (x 1000)	
		<u>MW</u>	<u>% of Total</u>	<u>Gwh</u>	<u>% of Total</u>		
Hydro	Water	644	5.8	2689	6.0	-	
Hydro Pumped Storage	Water	137	1.2	-	-	-	
Steam	Coal	5203	46.7	31514	70.6	17298	Tons
Steam	Oil	2843	25.5	3089	6.9	4620	Barrels
Steam	Gas	-		5426	12.2	56884	MCF
Steam	Nuclear	0	-	-	-	-	
Combustion Turbine	Oil	1470	13.2	158	0.4	416	Barrels
Combustion Turbine	Gas	-		346	0.8	4654	MCF
Combined Cycle	Oil	822	7.4	504	1.1	892	Barrels
Combined Cycle	Gas	-		931	2.1	9976	MCF
Geothermal	GST						
Internal Combustion	Oil	15	0.1	1	0	3	Barrels
Fuel Cell							
Other							
Total		11134	100.0	44658	100.0		
<u>Total Fuel Consumption</u>							
Coal (tons x 1000)		17298					
Gas (MCF x 1000)		71514					
Gas (equivalent bbls x 1000)		12120					
Oil: distillate (bbls x 1000)		856					
residual		5075					
crude		0					
Total Oil		5931					

Future Perspective

The combined Arizona - New Mexico Power Area peak loads are projected to increase at an average annual rate of 6.3 percent from 1980 to 1985. Energy consumption is estimated to increase at an average annual rate of 6.9 percent during the same period. While these growth rates are somewhat lower than the 7.6 and 7.1 percent rates for peak and energy experienced during the early 1970's, the rates are significantly higher than 4.5 and 5.4 percent peak and energy average annual growth rates recorded from 1976 through 1979.

During the period 1985 through 1989 the annual growth rates for peak demand and energy are projected to decrease considerably. The average annual growth rates are estimated to be 4.5 and 4.8 percent respectively.

Planned additions to the Region's generating capability total 4,332 MW during the period 1981 through 1985. Included in that total are 1,726 MW of coal-fired and 2,540 MW of nuclear generating capacity. The major unit additions are listed on Table 9C.5.

Table 9C.5

Scheduled Capability Additions (1981 - 1985)
Arizona - New Mexico Power Area

<u>Generating Unit and Number</u>	<u>Type</u>	<u>Net Capability MW</u>	<u>Schedule in Service Date</u>
Cholla 4	Coal	347	6/81
San Juan	Coal	472	6/82
Palo Verde 1	Nuclear	1270	5/83
Palo Verde 2	Nuclear	1270	5/84
Escalante 1	Coal	210	6/84
Challo 5	Coal	347	5/85
Springerville 1	Coal	350	6/85

Coal-fired generating capability is expected to increase to 49.2 percent of the total Region's generating capability in 1985. The two Palo Verde nuclear unit additions, the first in the Region, will contribute 12.6 percent of the total capability.

During the 1986 through 1989 period an additional 910 MW of coal-fired and 1270 MW of nuclear generating capability are planned to be added to the Region's generating capability. The total estimated capability additions for the same period amount to 2,538 MW.

The schedule for the major additions are listed on Table 9C.6.

Table 9C.6

Schedule Capability Additions (1986-1989)
Arizona - New Mexico Power Area

<u>Generating Unit & No.</u>	<u>Type</u>	<u>Net Capability</u>	<u>Scheduled in Service Date</u>
Palo Verde 3	Nuclear	1270	6/86
Springerville 2	Coal	350	6/87
Escalante 2	Coal	210	6/88
Pumped Storage	Hydro	300	5/89
Coronado 3	Coal	350	5/89

Fifty percent of the scheduled capability additions during the 1980 through 1989 periods are nuclear units followed by coal-fired units which account for 41.9 percent. Only 198 MW of new peaking oil/gas-fired units are scheduled to be installed during that period.

Considering the planned retirement of 140 MW of old oil/gas-fired units, the net addition amounts to only 58 MW.

Tables 9C.14 and 9C.15 show the estimated operation by type of plant and fuel consumption for the years 1985 and 1989.

Since the previous WSCC report, (formerly filed under FPC order 383-4) April 1, 1979, Palo Verde unit 1, 1270 MW, has been delayed one year to May 1983.

The first geothermal demonstration unit in the Imperial Valley, California is being planned for construction by San Diego Gas and Electric Company (SDG&E). The 50 MW Heber, California, project, will be tied in with Imperial Irrigation District's (IID) transmission system. IID will market the project's output. A 10 MW East Mesa pilot project has been under development for some time by SDG&E and Magma Corp. Indications are that the 50 MW binary demonstration unit will not be operational before 1983.

The planned additions schedule showing the amounts of capability to be added yearly for the years 1980 through 1989 is shown in Table 9C.16.

Delays in construction of new generating units would most likely result in increased fuel oil consumption. For the purpose of this report, a six months delay of the nuclear units was assumed to estimate the effects on fuel consumption. The estimated additional fuel oil burn as the result of delays is shown below.

Table 9C.7

Additional Fuel Consumption
For Delayed Generation Case
Arizona - New Mexico Power Area

<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
(Equivalent Barrels X 1,000)				
1,600	2,200	5,100	2,900	2,900

Part of the additional fuel consumption could be natural gas but no attempt was made to estimate that portion.

The forecasted Regional reserve margins for the 1980 through 1985 period range from 25.1 percent to 32.6 percent during the annual summer peak season. Projected reserves appear adequate and the estimated combined area reserve margins will meet the WSCC criteria 1 and 2 of the "Power Supply and Design Criteria" for all months in the 1980 to 1984 time period.

While the delay of Palo Verde has reduced expected reserve margins in 1982, no adverse consequences are anticipated. However, additional delays could result in inadequate reserves.

Table 9C.13 exhibits reserve margin projections for the summer and winter peak periods for the years 1981 through 1989. The effects of forced outage were considered using the average forced outage rate as recorded for the latest four years.

Although no further delays in construction are anticipated, the following table of estimated reserve margins indicated the effects of an additional one year delay in the Palo Verde units and a six months delay of the major coal-fired units during the 1980 through 1985 period.

Table 9C.8

	<u>Estimated Actual Reserve Margins (%)</u>					
	<u>Annual Summer Peak Period</u>					
	<u>Arizona - New Mexico Power Area</u>					
	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Present Schedule	22.0	29.4	24.5	28.5	30.8	20.9
Delayed Schedule	22.0	25.7	19.8	16.4	17.4	23.1

Planned critical bulk power transmission facilities that will not be in service when desired are reported by Public Service Company of New Mexico (PNM).

The OJO to Norton to B-A station 345 kV transmission line and the associated Norton 345/115 kV substation has been delayed from November 1980 to December 1982 due to right-of-way acquisition problems. This delay will stress the existing northern New Mexico transmission system and may result in marginal or unacceptable system performance under certain conditions.

Table 9C.11

Historical Capability(MW) and Reserves (MW and Present)
Arizona - New Mexico Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	11050	9461	9633	9685	9911	10727
2. Peak Demand	7266	5247	7942	6065	7942	6191
3. Planned Reserves (1-2)	3784	4214	1691	3620	1969	4536
4. Planned Reserves (%) (3+ 2) x 100%	52.1	80.3	21.3	59.7	24.8	73.3
5. Net Transactions (Imports-Exports)	-1067	160	391	86	174	137
6. Total Capability (1+5)	9983	9621	10024	9771	10085	10590
7. Total Reserves (6-2)	2717	4374	2082	3706	2143	4399
8. Total Reserves (%) (7+ 2) x 100%	37.4	83.4	26.2	61.1	27.0	71.1
9. Scheduled Maintenance	30	1346	175	1465	198	1352
10. Capability After Maintenance (6-9)	9953	8275	9849	8306	9887	9238
11. Reserves After Maintenance (10-2)	2687	3028	1907	2241	1945	3047
12. Reserves After Maintenance (%) (11+ 2) x 100%	37.0	57.7	24.0	36.9	24.5	49.2
13. Inoperable Capability	475	700	317	1736	437	12
14. Available Capability (10-13)	9478	7575	9532	6570	9450	9226
15. Available Reserves (14-2)	2212	2328	1590	505	1508	3035
16. Available Reserves (%) (15+ 2) x 100%	30.4	44.4	20.0	8.3	19.0	49.0
17. Forced Outages ^{1/}	0	0	0	0	0	0
18. Actual Capability After Forced Outage (14-17)	9478	7575	9532	6570	9450	9226
19. Actual Reserves (18-2)	2212	2328	1590	505	1508	3035
20. Actual Reserves (%) (19+ 2) x 100%	30.4	44.4	20.0	8.3	19.0	49.0

^{1/} Information not reported separately.

Table 9C.12

Current Capability (MW) and Reserves (MW) and Percent) - 1980
Arizona - New Mexico Power Area

	Summer 1980			Winter 1980-81		
	June	July	August	December	January	February
1. Planned Capability <u>1/</u>	11083	11088	11080	11541	11542	11551
2. Peak Demand	8624	8757	8669	6367	6475	6188
3. Planned Reserves (1-2)	2459	2331	2411	5174	5067	5363
4. Planned Reserves (%) (3+ 2) x 100%	28.5	26.6	27.8	81.3	78.3	86.7
5. Net Transactions (Imports-Exports)	23	35	34	148	53	46
6. Total Capability (1+5)	11106	11123	11114	11393	11595	11597
7. Total Reserves (6-2)	2482	2366	2445	5026	5120	5409
8. Total Reserves (%) (7+ 2) x 100%	28.9	27.0	28.2	78.9	79.1	87.4
9. Scheduled Maintenance	23	0	50	1361	1573	1965
10. Capability After Maintenance (6-9)	11073	11123	11064	10032	10022	9632
11. Reserves After Maintenance (10-2)	2454	2366	2395	3665	3547	3444
12. Reserves After Maintenance (%) (11+ 2) x 100%	28.5	27.0	27.6	57.6	54.8	55.7
13. Inoperable Capability	11	11	11	11	11	11
14. Available Capability (10-13)	11067	11112	11053	10021	10011	9621
15. Available Reserves (14-2)	2443	2355	2384	3654	3536	3433
16. Available Reserves (%) (15+ 2) x 100%	28.3	26.9	27.5	57.4	54.6	55.5
17. Forced Outages <u>2/</u>	430	430	430	660	660	660
18. Actual Capability After Forced Outage (14-17)	10637	10682	10623	9361	9351	8961
19. Actual Reserves (18-2)	2013	1925	1954	2994	2876	2773
20. Actual Reserves (%) (19+ 2) x 100%	23.3	22.0	22.5	47.0	44.4	44.8

1/ No delays anticipated in new generating units since submission of 1980 ERA-411

2/ Four year historical average forced outage (1976-1979).

Table 9C.13.1
Future Capability (MW) and Reserves (MW and Percent) 1981/1984
Arizona - New Mexico Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	13556	13549	14024	13991	15369	15337	16526	16519
2. Peak Demand	9431	6823	9937	7220	10484	7581	11061	8200
3. Planned Reserves (1-2)	4125	6726	4087	6771	4885	7756	5465	8319
4. Planned Reserves (%) (3+ 2) x 100%	43.7	98.6	41.1	93.8	46.6	102.3	49.4	101.5
5. Net Transactions (Imports-Exports)	-1346	-1495	-1640	-1703	-1810	-1880	-2046	-1898
6. Total Capability (1+5)	12210	12054	12384	12288	13559	13457	14480	14621
7. Total Reserves (6-2)	2779	5231	2447	5068	3075	5876	3419	6421
8. Total Reserves (%) (7+ 2) x 100%	29.5	76.7	24.6	70.2	29.3	77.5	30.9	78.3
9. Scheduled Maintenance	0	1007	0	778	79	1136	0	653
10. Capability After Maintenance (6-9)	12210	11047	12384	11510	13480	12321	14480	13968
11. Reserves After Maintenance (10-2)	2779	4224	2447	4290	2996	4740	3419	5768
12. Reserves After Maintenance (%) (11+ 2) x 100%	29.5	61.9	24.6	59.4	28.6	62.5	30.9	70.3
13. Inoperable Capability	11	27	11	27	11	27	11	27
14. Available Capability (10-13)	12199	11020	12373	11483	13469	12294	14469	13941
15. Available Reserves (14-2)	2768	4197	2436	4263	2985	4713	3408	5741
16. Available Reserves (%) (15+ 2) x 100%	29.4	61.5	24.5	59.0	28.5	62.2	30.8	70.0
17. Forced Outages <u>2/</u>	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outage (14-17)	12199	11020	12373	11483	13469	12294	14469	13941
19. Actual Reserves (18-2)	2768	4197	2436	4263	2985	4713	3408	5741
20. Actual Reserves (%) (19+ 2) x 100%	29.4	61.5	24.5	59.0	28.5	62.2	30.8	70.0

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ Information on forced outages not available.

Table 9C.13.2
Future Capability (MW) and Reserves (MW and Percent) 1985/1989
Arizona- New Mexico Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	17174	17167	18126	18108	18833	18826	19259	19207	19909	19901
2. Peak Demand	11887	8795	12513	9220	13155	9572	13632	9932	14149	10223
3. Planned Reserves (1-2)	5287	8372	5613	8888	5678	9254	5627	9275	5760	9678
4. Planned Reserves (%) (3+ 2) x 100%	44.5	95.2	44.9	96.4	43.2	96.7	41.3	93.4	40.7	94.7
5. Net Transactions (Imports-Exports)	-1836	-1920	-2010	-2094	-2134	-2218	-1899	-1624	-1549	-1633
6. Total Capability (1+5)	15338	15247	16116	16014	16699	16608	17360	17583	18360	18268
7. Total Reserves (6-2)	3451	6452	3603	6794	3544	7036	3728	7651	4211	8045
8. Total Reserves (%) (7+ 2) x 100%	29.0	73.4	28.8	73.7	26.9	73.5	27.3	77.0	29.8	78.7
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability After Maintenance (6-9)	15338	15247	16116	16014	16699	16608	17360	17583	18360	18268
11. Reserves After Maintenance (10-2)	3451	6452	3603	6794	3544	7036	3728	7651	4211	8045
12. Reserves After Maintenance (%) (11+ 2) x 100%	29.0	73.4	28.8	73.7	26.9	73.5	27.3	77.0	29.8	78.7
13. Inoperable Capability	11	27	11	27	11	27	11	27	11	27
14. Available Capability (10-13)	15327	15220	16105	15987	16688	16581	17349	17556	18349	18241
15. Available Reserves (14-2)	3440	6425	3592	6767	3533	7009	3717	7624	4200	8018
16. Available Reserves (%) (15+2) x 100%	28.9	73.1	28.7	73.4	26.9	73.2	27.3	76.8	29.7	78.4
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability After Forced Outage (14-17)	15327	15220	16105	15987	16688	16581	17349	17556	18349	18241
19. Actual Reserves (18-2)	3450	6425	3592		3533	7009	3717	7624	4200	8018
20. Actual Reserves (%) (19+ 2) x 100%	28.9	73.1	28.7	73.4	26.9	73.2	27.3	76.8	29.7	78.4

1/ Information on scheduled maintenance and forced outages not available.

Table 9C.14
Estimated 1985 Operation by Type of Plant
Arizona New Mexico Power Area

Plant Type	Fuel Type	Capability (as of 7/85)		Annual Energy		Fossil Fuel Consumption (x 1000)	
		MW	% of Total	Gwh	% of Total		
Hydro	Water	645	4.1	2553	4.0	-	
Hydro Pumped Storage	Water	137	0.9	-		-	
Steam	Coal	7785	49.2	40164	62.4	20632	Tons
Steam	Oil	2781	17.6	3062	4.8	5328	
Steam	Gas	-		2864	4.5	30355	MCF
Steam	Nuclear	1996	12.6	13197	20.5	-	
Combustion Turbine	Oil	1498	9.5	296	0.5	888	Barrels
Combustion Turbine	Gas	-		118	0.2	1590	MCF
Combined Cycle	Oil	534	1.0	1127	0.4	1898	Barrels
Combined Cycle	Gas	822	5.2	505	0.8	996	
Geothermal	GST	155	1.0	679	1.1		
Internal Combustion	Oil	15	0.1	1	-		
Fuel Cell	-	-					
Other							
Total		52859	100.0	272913	100.0		
<u>Total Fuel Consumption</u>							
Coal (tons x 1000)		20632					
Gas (MCF x 1000)		41420					
Gas (equivalent bbls x 1000)		6818					
Oil: distillate (bbls x 1000)		6122					
residual							
crude							
Total Oil		7579					

Table 9C.15
Estimated 1989 Operation by Type of Plant
Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of 7/89)		Annual Energy		Fossil Fuel Consumption (x 1000)	
		MW	% of Total	Gwh	% of Total		
Hydro	Water	645	3.6	2560	3.5	-	
Hydro Pumped Storage	Water	287	1.6	-		-	
Steam	Coal	8787	48.7	42708	58.3	21621	Tons
Steam	Oil	2689	14.9	2235	3.1	4030	Barrels
Steam	Gas	-		1089	1.5	11844	MCF
Steam	Nuclear	2994	16.6	22202	30.3	-	
Combustion Turbine	Oil	1548	8.6	247	0.3	661	Barrels
Combustion Turbine	Gas			5	0.0	77	MCF
Combined Cycle	Oil	822	4.6	420	0.6	786	Barrels
Combined Cycle	Gas			753	1.0	7329	MCF
Geothermal	GST	255	1.4	999	1.4	-	
Internal Combustion	Oil	15	0.1	3		8	Barrels
Fuel Cell	-						
Other							
Total		18047	100.0	73221	100.0		
Total Fuel Consumption							
Coal (tons x 1000)		21621					
Gas (MCF x 1000)		19250					
Gas (equivalent bbls x 1000)		3101					
Oil: distillate (bbls x 1000)		1079					
residual		4406					
crude							
Total Oil		5485					

Table 9C.16
Summary of Generation Additions
Arizona - New Mexico Power Area

(Winter Capability - MW)

<u>Generation Type</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>1989</u>	<u>10-Yr. Period</u>	<u>Percent of Total</u>
Hydro-Conventional	0	1	0	0	0	0	0	0	0	0	1	.0%
Hydro-Pump Storage	0	0	0	0	0	0	0	0	0	300	300	4.0%
Steam-Coal	592	347	445	-15	210	697	0	350	210	350	3186	2.2%
Steam-Gas and Oil	-11	0	-11	0	-26	0	-11	0	-81	0	-140	-1.8%
Nuclear	0	0	0	1270	1270	0	1270	0	0	0	3810	50.0%
Combustion Turbine	98	0	0	50	0	0	0	0	0	50	198	2.6%
Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	.0%
Geothermal			45	50	0	0	50	0	50	0	195	2.6%
Internal Combustion	0	0	0	0	0	0	0	0	0	0	0	.0%
Other	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>.0%</u>
Total	679	347	479	1355	1454	697	1309	350	179	700	7550	100.0%

Southern California-Nevada Power Area - Region 27Historical Perspective

The Southern California-Nevada Power Area (S.CA-NV) consists mainly of the service areas of Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Los Angeles Department of Water and Power (LADWP), and Nevada Power Company (NPC). These utilities operate independently but are joint participants in several generating plants.

The S.CA-NV experiences a pronounced summer peak. During the period 1960 through 1973 the region experienced an average annual growth in energy for load of 7.6 percent. However, for the period 1973 through 1979, this growth rate was reduced to less than two percent despite continued economic and population growth. SDG&E experienced the fastest energy for load growth rate with a 3.6 percent annual average increase from 1973 through 1978; conversely, LADWP has had a slightly negative load growth rate during the corresponding period.

Table 9D.1 presents electric load data for the years 1977-1979. Growth rate data appear high for 1978 because of the effects of conversion spurred by the 1976-1977 drought in California. The energy load decrease for 1979 is a probable reporting error as each utility in the Region experienced an actual load increase.

Table 9D.1
Historical Load Growth
Southern California-Nevada Power Area

	<u>1977</u>	<u>1978</u>	<u>1979</u>
Energy Load (GWh)	96666	102317	102014
Growth rate from previous year (%)	1.0	5.8	-0.3
Peak Demand (MW)	18815	20150	20507
Growth rate from previous year (%)	1.6	7.1	1.8
Load Factor (%)	58.6	58.0	56.8

The California utilities have historically relied heavily upon oil/gas fired additions to meet load growth requirements. Coal supplies are practically non-existent within the state and past economics and environmental concerns precluded major importation of coal for generating purposes.

As of December 1979 fully 67.8 percent of the Electric Region 27 installed generating capability was oil and/or gas fired. Gas and oil accounted for 63.7 percent of the total electric energy generation in 1978. For 1978, fuel oil consumption amounted to 70.8 million barrels and natural gas consumption was 18.4 billion cubic feet, which is equivalent to 31.4 million barrels of oil. Fuel consumption and generation data is not available for this Region for 1979.

This pronounced dependence on oil and gas as a fuel for generating purposes makes the California portion of this Region the largest consumer of oil and gas within the WSCC. The Nevada portion of the Region contains substantial amounts of coal-fired generation. Southern California utilities jointly own coal-fired generating capacity located in Southern Nevada and elsewhere. Their share of these units is included in Table 9D.10.

Oil and gas consumption is substantially reduced when better than adverse water conditions are experienced in the Pacific Northwest. During these periods surplus PNW hydroelectric energy is transferred to southern California consequently displacing incremental generation (usually oil) in the area. During the past several years Pacific Northwest secondary transfers to S.CA-NV averaged roughly 5,000 GWh, equivalent to 8 million barrels of oil per year.

Reliability criteria vary from utility to utility within the Southern California-Nevada area. However, the various criteria applied by each utility result in an area installed planning reserve margin requirement of approximately 20 percent at the time of the annual peak.

Table 9D.2
Reserve Margins (%)
Southern California-Nevada Power Area

	<u>1977</u>		<u>1978</u>		<u>1979</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
Total	33.3	68.5	29.9	60.2	22.2	67.9
Reserves						
after Main-	24.1	54.9	18.4	43.6	22.2	67.9
tenance						
Actual	19.6	37.8	6.1	35.0	3.1	31.7

Reserve margins have been low at the time of the past two summer peak periods due to excessive forced outage caused by the continuous

operation of system capacity in order to assist utilities to the north during energy shortages. Additionally, in 1979 the area experienced an early heat storm while scheduled maintenance of some major units was still in progress. SCE has been pursuing an aggressive maintenance program which is expected to reduce system forced outages by one third.

As of December 1979 the majority of the region's high voltage transmission was rated at 230 kV and totaled more than 4600 circuit miles. Strong 500 kV interties exist between Los Angeles, southern Nevada, Arizona, and New Mexico to the east, and to the north through northern California to the Pacific Northwest. The 800 kV-DC Pacific Northwest/Southwest intertie connects southern California with the Pacific Northwest. There are no intermediary taps along the DC intertie.

The combined northern AC and DC intertie is designated as the Pacific Intertie and in addition to firm transfers and significant seasonal diversity exchange the interties are used to transfer the aforementioned surplus hydro energy from the Pacific Northwest.

The total transfer capability between Electric Region 27 and northern utilities is approximately 3300 MW. Eastern transfer capability is 2300 MW from east to west and 900 MW from west to east.

While the existing transmission system is more than adequate to support intra-area and inter-area transfers, a problem area does exist in the region: the single 230 kV interconnection between SCE and SDG&E which carries participants' output of the San Onofre Nuclear Unit #1 and other transfers to SDG&E. This line is susceptible to outage brush fires and no appropriate back-up transmission exists.

Table 9D.3
1979 Capability by Type of Plant
Southern California-Nevada Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability(as of 12/31/79)</u>	
		<u>MW</u>	<u>% of Total</u>
Hydro	Water	2692	10.5
Hydro Pumped Storage	Water	1247	4.9
Steam	Coal	3871	15.1
Steam	Oil/Gas	14698	57.5
Steam	Nuclear	436	1.7
Combustion Turbine	Oil/Gas	1501	5.9
Combustion Cycle	Oil/Gas	1113	4.3
Internal Combustion	Oil	30	0.1
Total		25588	100.0

Table 9D.4

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Southern California - Nevada Power Area

	1977		1978		1979	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
1. Planned Capability	22197	22314	24771	25131	24156	24509
2. Peak Demand	18815	15125	20150	16355	20507	15432
3. Planned Reserves (1-2)	3382	7189	4621	8776	3649	9077
4. Planned Reserves (%) (3/2)x100	18.0	47.5	22.9	53.7	17.8	58.8
5. Net Transactions (Imports-Exports)	2877	3167	1404	1065	912	1406
6. Total Capability (1+5)	25074	25481	26175	26196	25068	25915
7. Total Reserves (6-2)	6259	10356	6025	9841	4561	10483
8. Total Reserves (%) (7/2)x100	33.3	68.5	29.5	60.2	22.2	67.9
9. Scheduled Maintenance	1730	2050	2318	2711	0	0
10. Capability after Maintenance (6-9)	23344	23431	23857	23485	25068	25915
11. Reserves after Maintenance (10-2)	4529	8306	3707	7130	4561	10483
12. Reserves after Maintenance (%) (11/2)x100	24.1	54.9	18.4	43.6	22.2	67.9
13. Inoperable Capability	840	2582	2482	1404	3921 <u>2/</u>	5595 <u>2/</u>
14. Available Capability (10-13)	22504	20849	21375	22081	21147	20320
15. Available Reserves (14-2)	3689	5724	1225	5726	640	4888
16. Available Reserves (%) (15/2)x100	19.6	37.8	6.1	35.0	3.1	31.7
17. Forced Outages <u>1/</u>	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	22504	20849	21375	22081	21147	20320
19. Actual Reserves (18-2)	3689	5724	1225	5726	640	4888
20. Actual Reserves (%) (19/2)x100	19.6	37.8	6.1	35.0	3.1	31.7

1/ Information not reported separately.

2/ Includes scheduled outages.

Table 9D.5

. CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Southern California - Nevada Power Area

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	22096	22303
2. Peak Demand	20805	17111
3. Planned Reserves (1-2)	1291	5192
4. Planned Reserves (%) (3/2)x100	6.2	30.3
5. Net Transactions (Imports-Exports)	4008	3745
6. Total Capability (1+5)	26104	26048
7. Total Reserves (6-2)	5299	8937
8. Total Reserves (%) (7/2)x100	25.5	52.2
9. Scheduled Maintenance	934	3100
10. Capability after Maintenance (6-9)	25170	22948
11. Reserves after Maintenance (10-2)	4365	5837
12. Reserves after Maintenance (%) (11/2)x100	21.0	34.1
13. Inoperable Capability	459	459
14. Available Capability (10-13)	24711	22489
15. Available Reserves (14-2)	3906	5378
16. Available Reserves (%) (15/2)x100	18.8	31.4
17. Forced Outages <u>2/</u>	1632	1575
18. Actual Capability after Forced Outages (14-17)	23079	20914
19. Actual Reserves (18-2)	2274	3803
20. Actual Reserves (%) (19/2)x100	10.9	22.2

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ 3-Year historical average forced outage (1976-78).

Present Perspective

Reserves above forecasted 1980 peak demands are expected to be adequate for the Southern California-Nevada Power Area. Expected 1980 reserves are in excess of minimum criteria partially as a result of peak demand growth reductions due primarily to expected increased energy conservation. Annual peak demand growth from 1979 to 1980 is projected to be 1.5 percent and energy load growth to be 3.4 percent.

The only scheduled resource additions in the area during 1980 are 57 MW of hydroelectric capacity in southern California and a 70 MW gas turbine unit planned by the Nevada Power Company.

The San Onofre Nuclear Unit No. 1 (436 MW) is scheduled for re-fueling from April 11 to June 1, 1980. Turbine blading problems have been experienced in units of similar age and type. Discovery of turbine trouble could extend the shutdown or cause derating of the unit.

The major southern California utilities participate in the state-wide emergency reserve sharing and demand reduction program (see discussion for Electric Region 28) and under this plan they may be called upon to assist the northern California utilities during possible capacity shortages there.

No surplus energy is expected from the Pacific Northwest, and Northwest economy receipts are anticipated to be significantly below average during 1980 due to below normal runoff predictions and already overdrafted reservoir conditions in the Northwest. This situation is estimated to result in an increased 1980 oil consumption in southern California of approximately 9 million barrels. Power plant fuel supplies are generally abundant throughout California.

Table 9D.6
1980 Installed Capability by Type of Plant
Southern California-Nevada Power Area (Region 27)

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capability</u>	
		<u>MW</u>	<u>% of Total</u>
Hydro	Water	2739	10.6
Hydro Pumped Storage	Water	1247	4.9
Steam	Coal	3871	15.1
Steam	Oil/Gas	14698	57.2
Steam	Nuclear	436	1.7
Combustion Turbine	Oil/Gas	1571	6.1
Combined Cycle	Oil/Gas	1113	4.3
Internal Combustion	Oil	30	0.1
Total		25705	100.0

Future Perspective

The utilities in the Southern California-Nevada Power Area (S.CA-NV) project load growth for the Region to average 3.0 percent in peak demand from 1980 to 1985 and 3.2 percent from 1985 through 1989. Associated annual energy load growth projections are 3.0 percent through 1985 and 3.3 percent from 1985 through 1989. These projections are significantly higher than actual growth rates experienced during the past several years.

In contrast to the utilities' forecast, the California Energy Commission (CEC) in its 1979 Biennial Report forecasts only a 2 percent growth in energy load through the 1980's for the major Southern California utilities which serve 90 percent of the Region's load. The CEC forecast is used in determining the need for additional generating resources during the State's powerplant site certification process.

Within the S.CA-NV, generating resource additions planned through 1985 include 2200 MW of nuclear capability (San Onofre 2 & 3), 500 MW of coal-fired capability in southern Nevada and 530 MW of combustion turbines.

Beyond 1985 significant amounts of coal-fired additions are planned. Continued expansion of combustion turbine capability is also scheduled. Other planned resources include hydro, geothermal, and wind. No nuclear units are planned within the area after the scheduled San Onofre unit additions. However, area utilities are joint participants in scheduled nuclear capacity outside of the S.CA-NV. These utilities' will share a total of 819 MW by 1990.

Table 9D.10 lists significant capability additions scheduled through 1989 for the Region. Table 9D.12 illustrates the utilities' projected generating capability listed by types for the years 1985 and 1989.

In conjunction with the CEC's recently adopted load forecast, the Commission has proposed a preferred resource mix which is significantly different from that foreseen by the California utilities. This CEC outlook capitalizes on alternative and renewable resources including increased development of geothermal, cogeneration, wind, and conservation with a proposed limit on coal-fired generation of 5800 MW. In contrast, present statewide utilities' plans include a total of nearly 12,000 MW of coal-fired generation by 1990.

Delays in construction of nuclear or coal-fired resources would most likely result in additional fuel oil consumption. Additional oil consumption is estimated to be nearly one million barrels per year per 100 MW of slippage. Assuming a one-year delay from the utilities' present scheduled in-service dates for nuclear, and six-months' delay for all coal-fired additions, fuel oil consumption would increase by about 2.1 million barrels in 1981, 10.4 million barrels in 1982, and 9.5 million barrels in 1983. During the five-year period through 1985, the resulting annual average increased oil burn is estimated to be 4.5 million barrels per year for S.CA-NV.

A recent development which will result in reduced area oil burn is Southern California Edison's agreement with Arizona Public Service Company (APS) to purchase power from APS's 350 MW coal-fired Cholla Unit No. 4 for a five-year period starting in June 1984. Under the terms of the agreement, SCE will receive 35 percent of the unit's capability the first year, 100 percent for the next three years and 41 percent for the final year. The purchase will reduce equivalent oil consumption by an estimated 12.5 million barrels during the five-year period.

Under the utilities' present resource schedule and peak load forecast, the actual reserve margins at the time of the system peak for the S.CA-NV area are projected to range from 10.9 percent in 1980 and 1981 to 23.5 percent in 1989.

Table 9D.7
Reserve Margins (%)
Southern California-Nevada Power Area

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Total	26.2	26.6	28.5	25.6	22.2
Reserves after Maintenance	21.0	21.9	22.0	21.3	27.2
Actual	18.8	19.8	19.7	21.0	21.4

Table 9D.8 shows the estimated installed reserve margins reflecting the effect of the delayed case for nuclear and coal-fired units. Reserves remain within desired margin requirements.

Table 9D.8
Estimated Actual Reserve Margins (%)
Southern California-Nevada Power Area

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Delayed schedule	18.8	14.8	13.7	21.0	20.8

Use of the lower CEC load forecast to determine reserves results in installed margins of up to 30 percent (1983) using the utilities presently scheduled capability additions. It may be assumed that scheduled additions will necessarily be delayed if the CEC's rigorous "need" determination continues as in past licensing hearings.

For S.CA-NV, only the effective dates for rerating two oil-fired units have been rescheduled since the April 1, 1979, WSCC report.

Table 9D.9
Schedule Capability Delay
Southern California-Nevada Power Area

<u>Unit Name & No.</u>	<u>Capability</u> <u>(MW)</u>	<u>Previous</u> <u>Date</u>	<u>New</u> <u>Date</u>	<u>Delay</u> <u>(months)</u>
Cool Water 4	+61	6/79	9/79	3
Long Beach 11	+56	7/79	1/81	17

Proposed bulk power line additions for the area through 1989 consist of 13 miles of 138 kV line, 342 miles of 230 kV line, 300 miles of 345 kV line, 1508 miles of 500 kV line, and 986 miles of 1000 kV (+ 500 kV) DC line. The DC line is scheduled to deliver Utah coal-fired capacity to southern California in the late 1980's. Also, the 540 mile existing 800 kV DC line from the Pacific Northwest to Sylmar is scheduled to be upgraded to 1000 kV in 1984.

The addition of two 230 kV lines by San Diego Gas and Electric Company is planned to overcome the existing deficiency associated with the San Onofre line as well as deliver added generator output in the early 80's. Additional 230 kV and 500 kV lines are proposed by the company to provide substantial ties with Mexico and eastern utilities by 1985.

Table 9D.10
Significant Planned Additions to Generating Capacity
Southern California-Nevada Power Area

<u>Unit</u>	<u>Type</u>	<u>Capability</u> <u>MW</u>	<u>Scheduled</u> <u>In-Service Date</u>
San Onofre 2	Nuclear	1100	10/81
San Onofre 3	Nuclear	1100	1/83
Reid Gardner 4	Coal	250	6/83
Warner Valley 1	Coal	63 1/	6/85
Warner Valley 2	Coal	63 1/	6/86
Harry Allen 1	Coal	230 2/	6/86
Intermountain 1	Coal	434 3/	7/86
Harry Allen 2	Coal	230 2/	6/87
Intermountain 2	Coal	434 3/	7/87
Harry Allen 3	Coal	230 2/	6/88
Intermountain 3	Coal	434 3/	7/88
California	Coal	500	9/88
Harry Allen 4	Coal	230 2/	6/89
Intermountain 4	Coal	434 3/	7/89
California 2	Coal	500	9/89

1/ 25% of 250 MW unit.
2/ 46% of 500 MW unit.
3/ 57.9% of 750 MW unit.

Table 9D.12
1985 and 1989 - Installed Capability by Type of Plant
Southern California-Nevada Power Area

<u>Plant Type</u>	<u>Fuel</u> <u>Type</u>	<u>1985</u>		<u>1989</u>	
		<u>Capability</u> <u>MW</u>	<u>Percent</u> <u>of Total</u>	<u>Capability</u> <u>MW</u>	<u>Percent</u> <u>of Total</u>
Hydro	Water	2875	9.8	3195	9.3
Pumped Storage	Water	1247	4.3	1247	3.6
Steam	Coal	4141	14.2	7582	22.1
Steam	Oil/Gas	14688	50.3	14567	42.3
Steam	Nuclear	3182	10.9	3455	10.0
Combustions Turbine	Oil/Gas	1854	6.3	2949	8.6
Combined Cycle	Oil/Gas	1144	3.9	1144	3.3
Geothermal		9	0.0	88	0.3
Internal Combustion	Oil	30	0.1	30	0.1
Cogeneration	---	47	0.2	60	0.2
Wind	---	3	0.0	84	0.2
Total		29220	100.0	34401	100.0

Table 9D.11.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Southern California - Nevada Power Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	22525	23616	23587	23798	24726	25005	24814	25054
2. Peak Demand	21238	17542	21975	18055	22633	18604	23369	19227
3. Planned Reserves (1-2)	1287	6074	1612	5743	2093	6401	1445	5827
4. Planned Reserves (%) (3/2)x100	6.1	34.6	7.3	31.8	9.2	34.4	6.2	30.3
5. Net Transactions (Imports-Exports)	4275	3834	4212	3995	4284	3981	4529	4063
6. Total Capability (1+5)	26800	27450	27799	27793	29010	28986	29343	29117
7. Total Reserves (6-2)	5562	9908	5824	9738	6377	10382	5974	9890
8. Total Reserves (%) (7/2)x100	26.2	56.5	26.5	53.9	28.2	55.8	25.6	51.4
9. Scheduled Maintenance	1111	2518	1003	1679	1754	2491	827	1912
10. Capability after Maintenance (6-9)	25689	24932	26796	26114	27256	26495	28516	27205
11. Reserves after Maintenance (10-2)	4451	7390	4821	8059	4623	7891	5147	7978
12. Reserves after Maintenance (%) (11/2)x100	21.0	42.1	21.9	44.6	20.4	42.4	22.0	41.5
13. Inoperable Capability	459	459	459	459	175	175	245	245
14. Available Capability (10-13)	25230	24473	26337	25655	27081	26320	28271	26960
15. Available Reserves (14-2)	3992	6931	4362	7600	4448	7716	4902	7733
16. Available Reserves (%) (15/2)x100	18.8	39.5	19.8	42.1	19.7	41.5	21.0	40.2
17. Forced Outages <u>2/</u>	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	25230	24473	26337	25655	27081	26320	28271	26960
19. Actual Reserves (18-2)	3992	6931	4362	7600	4448	7716	4902	7733
20. Actual Reserves (%) (19/2)x100	18.8	39.5	19.8	42.1	19.7	41.5	21.0	40.2

XI.9.67

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ Information on forced outages not available.

Table 9D.11.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Southern California - Nevada Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	25298	25759	27614	28070	29339	29800	31567	31675	33779	33840
2. Peak Demand	24172	19835	24962	20520	25814	21149	26664	21775	27461	22411
3. Planned Reserves (1-2)	1126	5924	2652	7550	3525	8651	4903	9900	6318	11429
4. Planned Reserves (%) (3/2)x100	4.7	29.9	10.6	36.8	13.7	40.9	18.4	45.5	23.0	51.0
5. Net Transactions (Imports-Exports)	4229	3945	3206	2909	2156	1855	1226	933	405	109
6. Total Capability (1+5)	29527	29704	30820	30979	31495	31655	32793	32608	34184	33949
7. Total Reserves (6-2)	5355	9869	5858	10459	5681	10506	6129	10833	6723	11538
8. Total Reserves (%) (7/2)x100	22.2	49.8	23.5	51.0	22.0	49.7	23.0	49.7	24.5	51.5
9. Scheduled Maintenance <u>1/</u>	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	29527	29704	30820	30979	31495	31655	32793	32608	34184	33949
11. Reserves after Maintenance (10-2)	5355	9869	5858	10459	5681	10506	6129	10833	6723	11538
12. Reserves after Maintenance (%) (11/2)x100	22.2	49.8	23.5	51.0	22.0	49.7	23.0	49.7	24.5	51.5
13. Inoperable Capability	175	175	269	269	269	269	269	269	269	269
14. Available Capability (10-13)	29352	29529	30551	30710	31226	31386	32524	32339	33915	33680
15. Available Reserves (14-2)	5180	9694	5589	10190	5412	10237	5860	10564	6454	11269
16. Available Reserves (%) (15/2)x100	21.4	48.9	22.4	49.7	21.0	48.4	22.0	48.5	23.5	50.3
17. Forced Outages <u>1/</u>	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	29352	29529	30551	30710	31226	31386	32524	32339	33915	33680
19. Actual Reserves (18-2)	5180	9694	5589	10190	5412	10237	5860	10564	6454	11269
20. Actual Reserves (%) (19/2)x100	21.4	48.9	22.4	49.7	21.0	48.4	22.0	48.5	23.5	50.3

1/ Information not available.

Northern California-Nevada Power Area (Region 28)Historical Perspective

The major service area within the Northern California-Nevada Power area (N.CA-NV) of the WSCC is the combined Pacific Gas and Electric Company (PG&E)/Sacramento Municipal Utility District (SMUD) area in northern California. The two utilities operate together (central dispatch) and serve approximately 90 percent of the total area electric load. In northern Nevada the major utility is the Sierra Pacific Power Company (SPP).

The N.CA-NV energy load growth averaged 6.6 percent annually from 1960 through 1973 and approximately 3 percent from 1973 through 1979. The area experiences a summer peak dominated by air conditioning and irrigation pumping loads. However, Sierra Pacific Power Company is a winter peaking utility.

During the winter of 1976-77 California experienced its worst drought record, consequently, hydroelectric powerplant output was dramatically reduced. The impact of the drought resulted in significant voluntary conservation and negative load growth from 1976 to 1977. The high peak demand growth figures for 1978 are artificially high because of this. 1979 showed a return to a more normal growth rate.

Table 9E.1
Historical Load Growth
Northern California-Nevada Power Area

	<u>1977</u>	<u>1978</u>	<u>1979</u>
Energy Load (GWh)	76044	79220	82690
Growth from previous year (%)	-1.3	4.2	4.4
Peak Demand (MW)	14461	15772	16016
Growth from previous year (%)	-1.1	9.1	1.5
Load Factor (%)	60.0	57.3	58.9

In 1978, an above average water year, hydro generation amounted to 28407 GWh or 41.2 percent of the area's total generation. At the end of 1979, the region's hydroelectric resources accounted for 36.8 percent of total area dependable capability. Other generating capability includes oil/gas-fired, geothermal, and nuclear, representing 53.1, 4.2, and 5.9 percent of the 1979 total capability, respectively.

Ninety-five percent of the area's oil and gas-fired generation is owned and operated by PG&E (SPP owns the remainder). The amount of natural gas burned in PG&E's steam units, which are capable of burning both oil and gas, varies depending on the fuel availability. Natural gas use has been averaging about 50 percent on a total Btu basis over the past several years. For 1978 the area's total oil burn for powerplant generating purposes was 31.2 million barrels and natural gas usage was 12.6 billion cubic feet, equivalent to 20.4 million barrels of oil. 1979 generation and fuel consumption data is not available for this area.

Geothermal development has continued at the Geysers location with 161 MW of capacity added in 1979 for a total of 663 MW of base load capability.

As of December 31, 1979, nuclear capacity in the area totalled 966 MW consisting of SMUD's Rancho Seco plant (875 MW summer and 903 MW winter capability) and PG&E's Humbolt Bay Unit #3 (63 MW) which has been out of service for the past 3 years. PG&E's Diablo Canyon Nuclear Units No. 1 and No. 2 (2190 MW) are essentially complete but remain off-line pending NRC licensing. To date, commercial operation of these units has been delayed nearly four years due to various licensing requirements. The licensing delay has been mainly the result of seismological safety design requirements as well as Three Mile Island related concerns. During the interim, additional oil consumption (the incremental fuel) is estimated at 20 million barrels per year.

Because of the delayed installation of the Diablo Canyon units coupled with the effect of higher than normal outages at thermal power plants, actual reserve margins for the PG&E/SMUD service area have been relatively low. N.CA-NV reserves have ranged from 10.3% to 12.9% for the past three summer and winter peak periods.

Table 9E.2
Reserve Margins (%)
Northern California-Nevada Power Area

	<u>1977</u>		<u>1978</u>		<u>1979</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
Total	21.5	49.6	15.4	35.9	20.2	37.3
Reserves after Maintenance	18.9	29.6	14.6	20.9	20.2	37.3
Actual	10.5	11.4	10.3	11.7	10.7	12.9

PG&E estimates northern California reserve requirements based on a loss of load probability of one day in ten years. The resultant installed reserve margin requirement is approximately 15 percent above the annual peak. Sierra Pacific requires a 17 percent reserve margin.

PG&E/SMUD service area available reserves have been down to 7 percent on several occasions over the past 3 years and PG&E officials have indicated concern over the high probability of load loss.

The bulk transmission network within N.CA-NV consists of 6668 miles of 115 kV lines, 6978 miles of 230 kV lines, and 1419 miles of 500 kV lines. The 500 kV system is part of the Pacific Intertie and is capable of inter-area transfers of approximately 2500 MW with the West Group of the Northwest Power Pool and 2000 MW with the N.CA-NV. The transfer capabilities are based on stability studies and are a function of load period and specific system conditions. In addition to contractual exchange, intertie capacity is used to transmit Northwest secondary hydro energy to California, to purchase economy energy, to exchange power and reserve support, and to accommodate major loop circulating flow.

The only existing interconnection between northern California and northern Nevada consists of two 115 kV lines which are limited to 160 MW west to east and 35 MW east to west. As such, SPP operates separately from northern California with the exception of a 108 MW firm contract with PG&E. The only other existing major line into the SPP service area is a 230 kV interconnection with the East Group of the Northwest Power Pool in Utah.

Another interconnection with the East Group which was originally scheduled for operation in 1977 was delayed to mid-1980 completion. This 400 MW 345 kV line presently under construction will link northern Nevada and southern Idaho. The major effects of the line delay reportedly have been increased oil consumption by SPP and reduced system reliability.

Table 9E.3

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Northern California - Nevada Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	15539	16086	16278	16432	16926	16517
2. Peak Demand	14461	11974	15772	12591	16016	12566
3. Planned Reserves (1-2)	1078	4112	506	3841	910	3951
4. Planned Reserves (%) (3/2)×100	7.5	34.3	3.2	30.5	5.7	31.4
5. Net Transactions (Imports-Exports)	2036	1822	1925	681	2327	730
6. Total Capability (1+5)	17575	17908	18203	17113	19253	17247
7. Total Reserves (6-2)	3114	5934	2431	4522	3237	4681
8. Total Reserves (%) (7/2)×100	21.5	49.6	15.4	35.9	20.2	37.3
9. Scheduled Maintenance	375	2394	132	1892	0	0
10. Capability after Maintenance (6-9)	17200	15514	18071	15221	19253	17247
11. Reserves after Maintenance (10-2)	2739	3540	2299	2630	3237	4681
12. Reserves after Maintenance (%) (11/2)×100	18.9	29.6	14.6	20.9	20.2	37.3
13. Inoperable Capability	1215	2177	671	1151	1523 <u>2/</u>	3062 <u>2/</u>
14. Available Capability (10-13)	15985	13337	17400	14070	17730	14185
15. Available Reserves (14-2)	1524	1363	1528	1479	1714	1619
16. Available Reserves (%) (15/2)×100	10.5	11.4	10.3	11.7	10.7	12.9
17. Forced Outages <u>1/</u>	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	15985	13337	17400	14070	17730	14185
19. Actual Reserves (18-2)	1524	1363	1528	1479	1714	1619
20. Actual Reserves (%) (19/2)×100	10.5	11.4	10.3	11.7	10.7	12.9

1/ Information not reported separately.

2/ Includes scheduled outages.

Table 9E.4
1979 Capability by Type of Plant
Northern California-Nevada Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>MW</u>	<u>% of Total</u>
Hydro		5553	34.9
Hydro Pumped Storage		295	1.9
Steam	Oil/Gas	7775	48.9
Steam	Nuclear	938	5.9
Combustion Turbine	Oil/Gas	440	2.8
Geothermal		663	4.2
Internal Combustion	Oil	50	0.3
Cogeneration	Oil/Gas	<u>179</u>	<u>1.1</u>
Total		15893	100.0

Current Perspective

Northern California utilities continue to operate under a high risk situation mainly because of the delay of bringing the Diablo Canyon nuclear units into service. Available reserve margins for N.CA-NV are expected to be only 9.14 percent this summer. This does not include the effects of forced outage. The 1980 margins reflect the expected above average hydro conditions and include more than 800 MW of short-term capacity for which PG&E has made arrangements.

Summer and winter peaks are forecast to grow 5.5 and 8.6 percent respectively over the same period of the preceding year. The only significant resource additions scheduled for 1980 consist of 245 MW of geothermal capability at the Geysers.

The estimated summer peak reserve margins for the area are higher than indicated in earlier studies because of late seasonal precipitation. Summer margins for the combined PG&E/SMUD service area were revised by the utilities based upon February 29, 1980, hydrological data as well as updated information on system thermal capacity and available purchases. Revised load forecasts were prepared based on the assumption that utility customers will observe approximately the same level of conservation as in 1979 (which presumes active utility appeals). These data indicate that northern California reserve margins will approximate 10 percent this summer, which is estimated to be the minimum acceptable margin necessary to cover expected forced outages.

The utilities' calculated reserve margins include the assumption that SMUD's Rancho Seco nuclear unit will be back on-line in early April following refueling and NRC required modification. Latest information indicates that Rancho Seco is presently on line.

Because of delays in bringing new resources on line and recent adverse hydrological conditions, California thermal-electric plants have operated at relatively high capacity factors leading to unusually high forced outage rates. After consideration of the historic five year-average forced outage, the northern California utilities' projected 1980 reserve margins are reduced to as little as 1.8 percent with Rancho Seco in service. Should PG&E experience higher than average forced outage rates, as was the case last year, utility officials state that either additional unidentified short-term capacity purchases will be required or rotating service outages will become necessary.

While some additional purchases from the Pacific Northwest have been included in the utilities' resource calculations, unused firm intertie capability remains available. However, the Northwest has experienced below normal precipitation this year and further purchases if available would probably be limited to capability with energy payback required within 24 hours of receipt.

The statewide critical period reserve sharing and load reduction plan remains in effect this year. Under this plan the State's five major electric utilities will share reserves if the operating reserve margin of any utility drops below 7 percent. Peak demand diversity between northern and southern California averages approximately 1000 MW. Load reduction measures will be implemented in three stages beginning when statewide reserves drop to 5 percent and calling for rotating circuit interruptions when reserves drop to 1.5 percent.

Transmission systems within the Northern California-Nevada Power Area are expected to be adequate to accommodate planned peak and energy transfers with one possible exception. Completion of the Mid-point-Valmy-Tracy 345 kV line between the Idaho and northern Nevada areas may result in relatively large magnitudes of circulating loop flow on the northern Nevada-northern California interconnection. Under certain conditions the northern Nevada-northern California interconnection may have to be opened to prevent overloading of the 115 kV system in the northern California area.

Table 9E.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Northern California - Nevada Power Area

	<u>1980 Summer</u>	<u>1980/81 Winter</u>
1. Planned Capability <u>1/</u>	17782	16709
2. Peak Demand	16896	13647
3. Planned Reserves (1-2)	886	3062
4. Planned Reserves (%) (3/2)x100	5.2	22.4
5. Net Transactions (Imports-Exports)	1265	395
6. Total Capability (1+5)	19047	17104
7. Total Reserves (6-2)	2151	3457
8. Total Reserves (%) (7/2)x100	12.7	25.3
9. Scheduled Maintenance	12	705
10. Capability after Maintenance (6-9)	19035	16399
11. Reserves after Maintenance (10-2)	2139	2752
12. Reserves after Maintenance (%) (11/2)x100	12.7	20.2
13. Inoperable Capability	550	368
14. Available Capability (10-13)	18485	16031
15. Available Reserves (14-2)	1589	2384
16. Available Reserves (%) (15/2)x100	9.4	17.5
17. Forced Outages <u>2/</u>	1206	1160
18. Actual Capability after Forced Outages (14-17)	17279	14871
19. Actual Reserves (18-2)	383	1224
20. Actual Reserves (%) (19/2)x100	2.3	9.0

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ 3-Year historical average forced outage (1976-78).

Table 9E.6
1980 Installed Capability by Type of Plant
Northern California-Nevada Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>Capacity</u>	
		<u>MW</u>	<u>Percent</u>
Hydro	Water	5560	34.5
Pumped Storage	Water	295	1.8
Steam	Oil/Gas	7775	48.2
Steam	Nuclear	938	5.8
Combustion Turbine	Oil/Gas	440	2.7
Geothermal	GST	908	5.6
Internal Combustion	Oil	50	0.3
Cogeneration		179	1.1
Total		16145	100.0

Future Perspective

Electric loads in northern California and northern Nevada have been projected by the area's utilities to increase at the rates of 3.3 percent per peak demand and 3.8 percent for energy for load over the five-year period from 1980 through 1985. For the following four-year period through 1989, the forecasted increase is 4.2 percent peak growth and 4.6 percent energy growth.

The recently adopted California Energy Commission (CEC) forecast for the northern California region is lower than that projected by the Region's utilities. The CEC forecast will be used by the Commission to determine the need for new generating facilities during the State's certification process. This forecast indicates a growth rate for the PG&E/SMUD service area of 2 percent in peak demand and energy through the decade of the 1980's.

PG&E has very recently (April 1980) announced the results of a new load forecast which has not yet been incorporated into the resource plan. The revised forecast is much closer to that projected by the Energy Commission, averaging 2.7 percent growth per year between 1980 and 2000.

The addition of the Diablo Canyon nuclear units is now scheduled for 1981. Any further delay could seriously jeopardize system reliability and cause additional fuel oil burn of nearly two million barrels per month. Other near-term scheduled capability additions through 1985 include 959 MW of geothermal, 552 MW of conventional hydro, 1120 MW of pumped storage hydro, 313 MW of coal-fired (including joint ownership in facilities outside of the Region), 378 MW of gas-fired combined cycle, and 691 MW of

cogeneration. If the Diablo Canyon nuclear units were delayed an additional year, and all coal and geothermal additions were delayed six months, the effect on fuel oil consumption would total about 25 million barrels over the five-year period through 1985, and coal and geothermal delays would account for approximately one million additional barrels of oil consumption annually.

Beyond 1985 the area's predominant scheduled additions include the continued development of geothermal potential and significant amounts of coal-fired capability. Major capacity additions (over 100 MW) are listed in Table 9E.10. In addition, PG&E's coal-fired plants planned for northern California in the late 1980's have tentatively been slipped one to two years due to reduced load growth. This slippage will result in a total of about 30 million barrels of additional fuel oil consumption per year of delay.

Table 9E.7 shows the major planned additions during the next five years which have been delayed from the schedule of one year ago.

Table 9E.7
Unit Delays from 3/79 - 3/80
Northern California-Nevada Power Area

Under Construction Unit & No.	Type	Capability (MW)	Scheduled In-Service Date		Delay (months)
			Present	Previous	
Geysers 13	Geothermal	135	4/80	10/79	6
Geysers 14	Geothermal	110	8/80	4/80	4
Diablo Canyon 1	Nuclear	1084	2/81	7/79	19
Diablo Canyon 2	Nuclear	1106	8/81	3/80	17
Helms P.S. 1	Hydro	374	12/81	6/81	6
Helms P.S. 2	Hydro	373	4/82	6/81	10
Helms P.S. 3	Hydro	373	5/82	6/81	11
Geysers 17	Geothermal	110	7/82	6/82	13
 Under Licensing					
Unit & No.					
Potrero 7	Combined Cycle	378	6/83	6/81	24
Kerckhoff 2	Hydro	151	10/83	12/82	10
Geysers 16	Geothermal	110	11/83	9/82	10

The PG&E/SMUD service area reserve margins are short of meeting even the minimum Reliability Council criterion for 1980 and 1981. Following the full commercial operation of Diablo Canyon, present schedules indicate adequate reserve margins for the Region.

Table 9E.8
Projected Reserve Margins (%)
Northern California-Nevada Power Area

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Total	10.1	22.1	20.4	18.1	17.1
Reserves after Maintenance	10.1	21.7	20.4	18.1	17.1
Actual	10.1	21.7	20.4	18.1	17.1

Further delays in bringing new generating units on-line could worsen the reserve shortage as indicated below. The delayed schedule is based on the aforementioned one year nuclear and six months coal and geothermal slippage.

Table 9E.9
Actual Reserve Margin (%)
Northern California-Nevada Power Area

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
Delayed Schedule	(2.6)	21.1	20.4	18.1	17.1

Scheduled transmission additions from 1980 through 1985 include 531 miles of 230 kV, 564 miles of 345 kV, 52 miles of 500 kV line. Additionally PG&E plans 357 miles of 500 kV line in the second half of the decade to deliver proposed northern California coal-fired generator output and to increase Pacific intertie capability.

The 52 mile Gates to Gregg 500 kV line has been rescheduled to May 1983, a 3 year delay resulting from State regulatory denial of certification. This delay will limit pump-back operation at the Helms pumped storage project and also restrict interconnection capability with the Southern California-Nevada Region.

Table 9E.10

Significant Planned Additions to Generating Capacity
Northern California-Nevada Power Area

<u>Unit Name & Number</u>	<u>Type</u>	<u>Capability (MW)</u>	<u>Scheduled In-service Date</u>
Geyzers 13	Geothermal	135	4/80
Geyzers 14	Geothermal	110	7/80
Diablo Canyon 1	Nuclear	1084	2/81
New Melones	Hydro	300	2/81
Diablo Canyon 2	Nuclear	1106	8/81
Valmy 1	Coal	125 <u>1/</u>	10/81
Helms	Pumped Storage	374	12/81
Helms	Pumped Storage	373	4/82
Helms	Pumped Storage	373	5/82
Potrero 7	Combined Cycle	273*	6/82
Geyzers 17	Geothermal	110	7/82
Geyzers 18	Geothermal	110	10/82
Kerckhoff 2	Hydro	113	10/83
Geyzers 16	Geothermal	110	11/83
Valmy	Coal	125 <u>1/</u>	10/84
Industrial Cogen.	Cogeneration	140	6/85
Oil Field Cogen.	Cogeneration	280	7/85
Geyzers 20	Geothermal	110	9/85
Harry Allen	Coal	230 <u>2/</u>	6/86
Geyzers 21	Geothermal	110	7/86 <u>3/</u>
Montezuma 1	Coal	800	7/86
Harry Allen 2	Coal	230 <u>2/</u>	6/87
Montezuma 2	Coal	800	7/87
Harry Allen 3	Coal	230 <u>2/</u>	6/88
Fossil 3	Coal	800	6/88 <u>3/</u>
Geothermal	Geothermal	110	6/88
Geothermal	Geothermal	110	6/88
Harry Allen 4	Coal	230 <u>3/</u>	6/89
Fossil 4	Coal	800	6/89 <u>3/</u>

1/ 50% of 250 MW unit.

2/ 46% of 500 MW unit.

3/ These units have recently been delayed one to two years

* To be converted to combined cycle operation at 378 MW
as of 6/83.

Table 9E.11.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Northern California - Nevada Power Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability <u>1/</u>	17875	19281	21023	20547	21230	21531	21760	21626
2. Peak Demand	17407	14206	17844	14610	18264	15138	19026	15876
3. Planned Reserves (1-2)	468	5075	3179	5937	2966	6393	2734	5750
4. Planned Reserves (%) (3/2)x100	2.7	35.7	17.8	40.6	16.2	42.2	14.4	36.2
5. Net Transactions (Imports-Exports)	1291	295	762	-148	762	-189	711	-321
6. Total Capability (1+5)	19166	19576	21785	20399	21992	21342	22471	21305
7. Total Reserves (6-2)	1759	5370	3941	5789	3728	6204	3445	5429
8. Total Reserves (%) (7/2)x100	10.1	37.8	22.1	39.6	20.4	41.0	18.1	34.2
9. Scheduled Maintenance	0	1413	64	1631	0	1812	0	1227
10. Capability after Maintenance (6-9)	19166	18163	21721	18768	21992	19530	22471	20078
11. Reserves after Maintenance (10-2)	1759	3957	3877	4158	3728	4392	3445	4202
12. Reserves after Maintenance (%) (11/2)x100	10.1	27.9	21.7	28.5	20.4	29.0	18.1	26.5
13. Inoperable Capability	5	7	5	7	5	8	5	8
14. Available Capability (10-13)	19161	18156	21716	18761	21987	19522	22466	20070
15. Available Reserves (14-2)	1754	3950	3872	4151	3723	4384	3440	4194
16. Available Reserves (%) (15/2)x100	10.1	27.8	21.7	28.4	20.4	29.0	18.1	26.4
17. Forced Outages <u>2/</u>	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	19161	18156	21716	18761	21987	19522	22466	20070
19. Actual Reserves (18-2)	1754	3950	3872	4151	3723	4384	3440	4194
20. Actual Reserves (%) (19/2)x100	10.1	27.8	21.7	28.4	20.4	29.0	18.1	26.4

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ Information on forced outages not available.

Table 9E.11.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Northern California - Nevada Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22616	22773	23852	23889	25531	24795	26493	25785	27351	26374
2. Peak Demand	19902	16644	20720	17455	21611	18250	22505	19139	23442	19794
3. Planned Reserves (1-2)	2714	6129	3132	6434	3920	6545	3988	6646	3909	6580
4. Planned Reserves (%) (3/2)x100	13.6	36.8	15.1	36.9	18.1	35.9	17.7	34.7	16.7	33.2
5. Net Transactions (Imports-Exports)	698	-246	943	3	540	238	777	475	1007	655
6. Total Capability (1+5)	23314	22527	24795	23892	26071	25033	27270	26260	28358	27029
7. Total Reserves (6-2)	3412	5883	4075	6437	4450	6783	4765	7121	4916	7235
8. Total Reserves (%) (7/2)x100	17.1	35.3	19.7	36.9	20.6	37.2	21.2	37.2	21.0	36.6
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	23314	22527	24795	23892	26071	25033	27270	26260	28358	27029
11. Reserves after Maintenance (10-2)	3412	5883	4075	6437	4460	6783	4765	7121	4916	7235
12. Reserves after Maintenance (%) (11/2)x100	17.1	35.3	19.7	36.9	20.6	37.2	21.2	37.2	21.0	36.6
13. Inoperable Capability	5	8	5	8	5	8	5	8	5	7
14. Available Capability (10-13)	23309	22519	24790	23884	26066	25025	27265	26252	28353	27022
15. Available Reserves (14-2)	3407	5875	4070	6429	4455	6775	4760	7113	4911	7228
16. Available Reserves (%) (15/2)x100	17.1	35.3	19.6	36.8	20.6	37.1	21.2	37.2	20.9	36.5
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	23309	22519	24790	23884	26066	25025	27265	26252	28353	27022
19. Actual Reserves (18-2)	3407	5875	4070	6429	4455	6775	4760	7113	4911	7228
20. Actual Reserves (%) (19/2)x100	17.1	35.3	19.6	36.8	20.6	37.1	21.2	37.2	20.9	36.5
<u>Coal Unit Delays Assumed Possible by ERA</u>										
21. Possible Coal Delays 2/	0	0	800	800	800	800	800	800	800	800
22. Actual Capability w/Nuclear & Coal Delays (18-21)	23309	22519	23990	23084	25266	24225	26465	25452	27553	26222
23. Actual Reserves w/Nuclear & Coal Delays (22-2)	3407	5875	3270	5629	3655	5975	3960	6313	4111	6428
24. Actual Reserves w/Nuclear & Coal Delays (%) (23/2)x100	17.1	35.3	15.8	32.2	16.9	32.7	17.6	33.0	17.5	32.5

XI.9.81

1/ Information not available.

2/ These units have recently been delayed 1 to 2 years from the dates shown.

Table 9E.12
1985 and 1989 Installed Capacity by Type of Plant
Northern California-Nevada Power Area

<u>Plant Type</u>	<u>Fuel Type</u>	<u>1985</u>		<u>1989</u>	
		<u>Capability</u> <u>MW</u>	<u>Percent</u> <u>of Total</u>	<u>Capability</u> <u>MW</u>	<u>Percent</u> <u>of Total</u>
Hydro	Water	5818	26.7	6023	23.8
Pumped Storage	Water	1430	6.6	1430	5.7
Steam	Coal	313	1.4	3145	12.4
Steam	Oil/Gas	7669	35.2	7319	28.9
Steam	Nuclear	3128	14.4	3128	12.4
Combustion					
Turbine	Oil/Gas	440	2.0	530	2.1
Combined Cycle	Oil/Gas	378	1.7	378	1.5
Internal					
Combustion	Oil	50	0.2	50	0.2
Geothermal	GST	1622	7.4	2112	8.3
Cogeneration		870	4.0	1120	4.4
Other		80	0.4	80	0.3
Total		21798	100.0	25315	100.0

Electric Regions in the United States

June 1, 1980 *

* First revision of July 1, 1979 map.

Electric Region	Identification				
1	Allegheny Power System (APS)	5	MAAC	7	SERC
2	American Electric Power System (AEP)	6	MAIN	9	Florida Coordination Group (FCG)
13	Central Area Power Coordination Group (CAPCO)	17		11	Southern Company Group
14	Cincinnati, Columbus, Dayton Group (CCD)	19		12	Tennessee Valley Authority Group (TVA)
15	Kentucky Group	20	MARCA	22	Virginia-Carolinas Group (VACAR)
16	Indiana Group - All Indiana Utilities except I&M Electric Co.			8	SWPP
18	Michigan Electric Coordinated Systems (MECS)	3	NPCC	10	Middle South Utilities Group
23	ERCOT Texas Interconnected Systems Group (TIS)	4		21	Gulf States Group
				22	Missouri-Kansas Group (MOKAN)
				24	Oklahoma Group
				25	WSCC
				26	Rocky Mountain Power Pool (RMPP)
				27	Northwest Power Pool (NWPP)
				28	Except for Idaho-Utah Group
				30	Arizona-New Mexico Group
					Southern California-Nevada Group
					Northern California-Nevada Group
					Idaho-Utah Group of the Northwest Power Pool