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Staff Report

Estimated Winter 1980-81 Electric Demand and Supply, Contiguous United States.

December 1980

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

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Division of Power Supply and Reliability
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DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Staff Report on Projected Winter 1980-81
Electric Load-Supply Situation

SUMMARY

This report summarizes the most recent data available concerning projected electrical peak demands and available power resources for the 1980-81 winter peak period, as reported by electric utilities in the contiguous United States. The data, grouped by Regional Reliability Council^{1/} areas and by Electrical Regions^{1/} within the Council areas, was obtained from the Form 12E-2 reports filed by utilities with the Department of Energy on October 15, 1980 (data as of September 30). In some instances the data has been revised or verified by telephone. Considerations affecting reliability, arising from Nuclear Regulatory Commission actions based on "lessons learned" from the forced outage of Three Mile Island Nuclear Unit No. 2, have been factored into this report.

No wide-spread large-scale reliability problems are foreseen for electric power supply this winter, on the basis of the supply and demand projections furnished by the electric utilities. In some electric regions reserve margins could drop to levels considered inadequate for reliable service, if historical forced outage magnitudes recur. These areas are

Electric Region

- 1 Allegheny Power System
- 13 CAPCo Group
- 16 Indiana Group
- 6 Commonwealth Edison Co.
- 10 Gulf States Group
- 7 Florida

1/ See Maps in Appendix 1.

If projected demands occur and the possible large-scale outages of capacity take place, in these Regions, customers may experience unreliable service^{1/} during the winter months. However, the reserves listed for these Regions must be viewed in the context of the capacity available within the corresponding Reliability Council area and the ability of the transmission network to make that capacity available where needed. Careful management of generating and transmission facilities by utility personnel engaged in system operation will be necessary if difficulties are to be minimized.

Data for the ECAR area reflect the incorporation of the Columbus and Southern Ohio Electric Co. System into the American Electric Power System to the extent information is available.

"Unreliable" is a qualitative term that includes conditions ranging from minor reductions in voltage for short periods to long-term major voltage reductions, frequency fluctuations, unplanned interruptions to service, and planned rotating interruptions.

REGIONAL OUTLOOK

Each of the Regional Electric Reliability Council areas, as a whole, has a projected reserve margin that would be satisfactory under normal conditons (Table A).

These margins, which include the effects of capacity purchases and sales transactions between Council areas, scheduled maintenance and capacity known to be unavailable, and forced outages, range from 8.1% to 35.1% of peak demand projected for the Council. Table B shows the Electric Region reserve margins.

Customer service reliability cannot be directly deduced from Council or Regional reserve margin, since much depends on the daily and weekly variation in load, the interconnections among systems, each individual utility's internal transmission, generation facilities and other factors. It is generally agreed, however, that reserve margins of the magnitude shown with an asterisk in Table B would be too low for consistently reliable service. For each of these Electric Regions, capacity purchases on an emergency basis may be needed. Such capacity appears to be available, for each of these Regions, from systems within their Reliability Council area.

Table A
Summary of Council Area Supply and Demand
Winter Peak Period 1980-81

Reliability Council Area	Total ^{1/} Capability MW	Estimated Peak Load MW	Total Reserve MW	%	Estimated ^{2/} Outages MW	Reserve After Outages MW	%
ECAR	92,476	64,227	28,249	44.0	23,076	5,173	8.1
MAAC	47,981	29,440	18,541	63.0	11,818	6,723	22.8
MAIN	41,942	27,373	14,569	53.2	12,073	2,496	9.1
MARCA	24,901	16,834	8,067	47.9	2,157	5,910	35.1
NPCC	52,784	36,098	16,686	46.2	10,080	6,606	18.3
SERC	118,598	86,253	32,345	37.5	22,863	9,482	11.0
SWPP	55,057	31,918	23,139	72.5	12,409	10,730	33.6
Subtotal	433,739	292,143	141,596	48.5	94,476	47,120	18.1
ERCOT	43,256	22,424	20,832	92.9	13,097	7,735	34.5
WSCC	105,117	74,607	30,510	40.9	14,196	16,314	21.9
Total	582,112	389,174	192,938	49.6	121,769	71,169	18.3

1/ Includes the net of scheduled imports and exports

2/ The sum of scheduled maintenance, estimated full and partial forced outages and capability unavailable for other reasons.

General Note: The data in this table are valid for the peak non-coincidental demand of each Council. The peak non-coincidental demand was obtained for each Council by summing the peaks projected for each utility in that Council. The utility peaks may occur at different times, therefore the Council peak tabulated may exceed (by no more than some 1 or 2 percent) the actual coincident peak demand. For the same reason, the "Subtotal" and "Total" peak loads in the table may exceed the actual coincidental peak of the Councils as a group. In the case of wide-spread extreme weather conditions, the coincident and non-coincident Council peaks can be very nearly the same, and the "Subtotal" and "Total" peaks can also approach identity.

The timing factor also affects the scheduled imports and exports included in the column headed "Total Capability" and the column headed "Estimated Outages".

For the reasons stated, the tabulated data are to be regarded as the best estimates available, approximately correct, but not exact numbers susceptible of verification at a specified time.

Table B
Electric Regions
Power Supply and Demand
Winter Peak Period 1980-1981

		^{1/} Total Capability MW	Estimated Peak Load MW	Total Reserve		^{2/} Estimated Outages MW	Reserve After Outages		
	Electric Region			MW	%		MW	%	
1	APS	8,045	5,260	2,785	52.9	3,270	(485)	(9.2)	*
2	AEP	24,469	17,397	7,072	40.7	5,581	1,491	8.6	
13	CAPCo	16,120	10,954	5,166	47.2	5,352	(186)	(1.7)	*
14	CD	6,973	4,666	2,307	49.4	1,526	781	16.7	
15	KENTUCKY	8,290	5,858	2,432	41.5	832	1,600	27.3	
16	INDIANA	11,628	9,200	2,428	26.4	2,640	(212)	(2.3)	*
18	MECS	16,951	10,892	6,059	55.6	3,875	2,184	20.1	
23	ERCOT	43,256	22,424	20,832	92.9	13,097	7,735	34.5	
5	MAAC	47,981	29,440	18,541	63.0	11,818	6,723	22.8	
6	CECo	18,241	10,780	7,461	69.2	7,553	(92)	(0.9)	*
17	ILLMO	14,994	10,224	4,770	46.7	3,179	1,591	15.6	
19	WUMS	8,707	6,369	2,338	36.7	1,341	997	15.7	
20	MAPP	24,901	16,834	8,067	47.9	2,157	5,910	35.1	
3	NEPOOL	21,643	16,075	5,568	34.6	3,542	2,026	12.6	
4	NYPP	31,141	20,023	11,118	55.5	6,538	4,580	22.9	
7	FLORIDA	23,995	19,090	4,905	25.7	4,376	529	2.8	*
9	SOCO	27,777	17,913	9,864	55.1	6,000	3,864	21.6	
11	TVA	29,644	20,952	8,692	41.5	4,861	3,831	18.3	
12	VACAR	37,182	28,298	8,884	31.4	7,626	1,258	4.4	
8	MSU	14,879	8,106	6,773	83.6	4,573	2,200	27.1	
10	GULF	9,213	6,029	3,184	52.8	3,339	(155)	(2.6)	*
21	MOKAN	13,285	7,735	5,550	71.8	2,189	3,361	43.5	
22	OKLA	17,680	10,048	7,632	76.0	2,308	5,324	53.0	
24	RMPP	6,559	5,148	1,411	27.4	369	1,042	20.2	
25	NWPP	42,204	33,245	8,959	26.9	3,665	5,294	15.9	
30									
26	A-NM	12,640	6,914	5,726	82.8	2,486	3,240	46.9	
27	SC-N	26,798	16,394	10,404	63.5	4,775	5,629	34.3	
28	NC-N	16,916	12,906	4,010	31.1	2,881	1,129	8.7	

^{1/} Includes the net of scheduled imports and exports.

^{2/} The sum of scheduled maintenance, estimated full and partial forced outages and capability unavailable for other reasons.

* "Reserve after outages" is too low for consistently reliable service. If these reserves are actually experienced, reliability of service will be jeopardized, but could be maintained by transmission of power from other Regions within the Council area.

1. EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)

The East Central Area Reliability Coordination Agreement (ECAR) consists of nineteen member systems in seven power pooling groups which serve all or parts of the States of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland, and Tennessee. In addition, the area covered by ECAR includes a number of small systems described as "Liaison Members" of ECAR.

The ECAR noncoincident peak load forecast for the winter season 1980-81 is 64,227 megawatts (see Table 1.1). This reflects a 7.3 percent increase over the actual peak of the previous winter but only a 1.4 percent increase over the winter peak of 1978-79. The peak of the 1979-80 winter season was depressed due to the unusually mild winter and the depressed state of the economy.

ECAR as a whole is a winter peaking area, although many of its members peak in the summer. This allows each subregion within ECAR to take advantage of intrasystem diversity in scheduling maintenance, capacity transfers, and in establishing reserve criteria.

Planned capability to meet the 1980-81 winter peak load forecast is 92,309 megawatts. Included in this total is 2,860 of new coal-fired capacity installed since last summer: Campbell No. 3, Mansfield No. 3, and Mountaineer No. 1. Pleasants No. 2, originally scheduled for service in October 1980, has been delayed until December and is not included in planned capability.

Of the 92,309 MW of planned generating capability, more than 80 percent is coal-fired, utilizing coal produced primarily within the region, from the Appalachian coal fields. Nuclear generating capacity is about 5 percent of installed capability. Table 1.2 shows projected generation by fuel type for January 1981, based on ERA-Form 160. Table 1.3 provides fuel use projections for oil and gas for January 1981 and actual use for January 1980. Pressures to reduce the use of oil and gas, stemming from increasing oil prices and uncertainty as to oil availability are reflected in the 1981 projections.

Line 17 of Table 1.1 shows possible forced outages for each of the regional groups in ECAR. These were developed individually, based on the generating capacity unavailable at the time of the winter peak for the past three winters. The 3-year average capacity on forced outage varies from 832 MW for the Kentucky Group to 4337 MW for the CAPCO group. The 3-year average forced outage in megawatts is used as representative of the forced outages and unavailable capability that could be experienced in the winter of 1980-81.

As shown on Table 1.1 for winter 1980-81, the ECAR region should have adequate reserves to meet its load responsibility. Although some electric regions could have a deficit in actual reserves, based on historical data of the 3-year averages of forced outages, sufficient reserve capacity exists in the total ECAR area, and the transmission system is adequate to provide energy and capacity transfers, should any unusual problems arise.

The Electric Regions in ECAR are:

American Electric Power Group (AEP)

Allegheny Electric Power System (APS)

Central Area Power Coordination Group (CAPCO)

Cincinnati-Dayton Group (CD)

Indiana Group

Kentucky Group

Michigan Electric Coordinated Systems (MECS)

These regions are discussed in detail in the following pages. Table 1.1 shows for each Electric Region, planned capability; projected demand; reserves; the capability that might be unavailable for various reasons, and the resulting reserve.

Tables 1A.1, 1B.1 and 1C.1 show, for APS, AEP and CAPCO, respectively, the capability unavailable at the time of peak winter demand, for the past three winters.

American Electric Power Group (AEP)
Electric Region 2

The American Electric Power System Region includes American Electric Power Company, Buckeye Power Inc., Ohio Valley Electric Corporation and Columbus & Southern Ohio Electric Company. The American Electric Power Company is an electric utility holding company comprising seven wholly owned subsidiary companies operating in parts of seven states; Ohio, Indiana, Michigan, West Virginia, Virginia, Kentucky, and Tennessee. AEP recently acquired the properties of Columbus and Southern. For this report the forecast figures include C&SOE Co. and previous regional figures have been adjusted for comparison purposes. Buckeye Power Inc. is essentially an association of all the electric cooperatives in the State of Ohio. The Ohio Valley Electric Corporation (OVEC) was originally formed by a consortium of ten electric companies in ECAR to provide electric power to the Department of Energy's Uranium Enrichment Plant in Portsmouth, Ohio.

The AEP region is a winter peaking area. The peak forecast for the winter 1980-81 is 17,397 megawatts. This is 8.8 percent over the actual peak of the previous winter, and a decline of 1.8 percent from the winter peak of 1978-79. Peaks have fluctuated in this area because of changing contractual sales of OVEC to intra-regional utilities and weather sensitivity.

Planned capability to meet the coming winter peak load is 25,625 megawatts. No major capacity additions are included in the planned capability for the coming winter season. The Mountaineer No. 1 coal-fired unit (1300 MW) previously scheduled for service in

December 1980 went commercial September 15, 1980, and is included as planned capability. The Smith Mountain Pumped Storage unit scheduled for service in February 1980 went commercial in June 1980.

Almost 88 percent of the current capability in the region is coal-fired steam capacity, and 8.5 percent is nuclear. AEP's policy of having large planned reserves of coal-fired generation, and a strong transmission system, are used to advantage by selling capacity to other utilities in the region.

Capacity out for scheduled maintenance over the past three winter seasons averaged 1,283 megawatts; forced outages and unavailable capability averaged 3,530 megawatts. Forecasted scheduled maintenance for the coming winter season is 2,051 megawatts. The three-year average forced outage has been included in Table 1.1, line 17, as representative of the probable forced outage and unavailable capability that could be expected for the AEP region for the coming season.

The AEP group has no contracts with systems in reliability councils adjoining ECAR for scheduled transfers of power. However, there are many firm and nonfirm contracts with companies in ECAR.

As shown in Table 1.5 for the winter 1980-81, the AEP group planned reserves based on installed capability are 47.3 percent. Actual reserves after possible unit outages for the region could drop to .6 percent. This should be sufficient to meet the load responsibility of the AEP system since it factors in the adverse effects of outages that could normally be expected.

The 765 kV Gavin-Belmont transmission line, which is needed to move the output of the Mountaineer No. 1 generating unit into the AEP system, became operational as of September 15, 1980. No other major transmission lines are scheduled for initial service during the winter peak load season.

Allegheny Power System (APS)
Electric Region 1

The Allegheny Power System, Inc. (APS) is the parent company of an integrated electric system comprising the properties of the Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and their subsidiaries. The three operating companies serve over 1 million customers in southwestern and north central Pennsylvania, the northern portion of West Virginia, the western portion of Maryland and a small portion of northwestern Virginia.

The Allegheny Power System is a winter peaking area. The peak forecast for the winter 1980-81 is 5,260 megawatts. This is 12 megawatts less than the actual 1979-80 winter peak demand. Winter peak demand has been declining for the last three years in the APS area. APS indicates that this decline has been the result of mild winters, conservation, and economic conditions (particularly in the coal and steel industries), and is reflected in the projection for winter 1980-81.

Planned capability to meet the expected winter peak load is 7,587 megawatts. No major additions are included in the planned capability for the coming winter season.

Almost 93 percent of current capability is vested in coal-fired steam generation. There are no nuclear units installed on the system, and hydroelectric and oil-fired generation are insignificant.

Capacity out for scheduled maintenance over the past three winter seasons averaged 460 megawatts; the total of forced outages and unavailable capability averaged 2,218 megawatts. Forecasted

scheduled maintenance for the coming winter season is 1,052 megawatts. The three-year average forced outage is included in Table 1.1 line 17, as representative of the forced outage and unavailable capability that could occur for APS. There has been a substantial increase in the APS forced outage rate over the last few years as a result of persistent and lengthy outages of the larger units on the system. The 2,118 megawatts represents 40.3 percent of the projected peak.

APS states that construction slippage has occurred on the Pleasants No. 2 unit, since the April 1980 ERA-411 report. Originally scheduled to be operational in October 1980, the unit has been rescheduled to December 1980 and has not been included as available for the peak period.

Scheduled contract purchases include a firm 300-megawatt diversity exchange with Virginia Electric and Power Company (VEPCO) and a nonfirm purchase of 158 megawatts from the Ohio Valley Electric Company. The 300 megawatts from VEPCO is to be returned during the summer peak period.

As indicated in Table 1.1 for the winter 1980-81, the APS region's planned reserves of 44.2 percent, and the possible available reserves of 32.9 percent, respectively, appear adequate. If, however, the previous high incidence of forced outages is again experienced, the actual reserves would be a negative 485 megawatts or -9.2 percent.

For the 1980-81 winter season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no areas posing stability problems.

Central Area Power Coordination Group (CAPCo)
Electric Region 13

This region includes the Central Area Power Coordination Group (CAPCo) and the Cleveland Municipal System. CAPCo consists of five investor-owned electric utilities providing service in northern Ohio and western Pennsylvania. The systems are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company.

CAPCo is a summer peaking area and the peak forecasted for the winter 1980-81 is 10,954 megawatts. This represents a 4.9 percent increase over the actual peak of the previous winter, but only a 1.0 percent increase over the peak of the winter two years ago. The 1979-80 winter peak was depressed due to the unusually mild weather.

Planned capability to meet the projected winter peak load is 15,641 megawatts. The Mansfield Unit No. 3 previously scheduled for completion in October 1980 was declared commercial September 29, 1980, and is included in the planned capability available for the winter peak season. No other major capacity additions are scheduled for this period.

Approximately 77 percent of the current capability is coal-fired steam generation, 11.5 percent is nuclear-fueled, and 4.4 percent is baseload oil.

Capacity out for scheduled maintenance over the past three winter seasons averaged 1,361 megawatts and forced outages and unavailable capability averaged 4,337. Forecasted scheduled maintenance for

the coming winter season is 1,015 megawatts. The three-year average forced outages are included in Table 1.1, line 17, as representative of the forced outages and unavailable capability that could occur for the CAPCo area. The CAPCo region has no contracts for scheduled power transfers with systems in reliability councils adjoining ECAR; however, some intra-regional contracts exist.

As indicated on Table 1.1 for the winter 1980-81, the CAPCo region's planned reserves of 42.8 percent and the possible available reserves of 37.9 percent, respectively, appear adequate. If, however, the historical high incidence of forced outages continues, the actual reserves would be reduced to a negative 186 megawatts or - 1.7 percent.

For the 1980-81 winter season, only the Mansfield-Hanna 345 kV line still appears as a constraint. This line, originally scheduled for service in 1977, is under litigation and an 8.7-mile section is still to be completed.

Cincinnati-Dayton Group-CD
Electric Region 14

This region includes the Cincinnati Gas & Electric Co., the Dayton Power and Light Company and the municipal system of Hamilton, Ohio. Hamilton has not reported and has not been included in the data. Columbus & Southern Ohio Electric Company, formerly a member of this group and part of the electric region for reporting purposes, has been purchased by American Electric Power System and is now included in the AEP area, instead of Electric Region 14. Historical data used in this report has been adjusted to reflect this change.

The CD group is a summer peaking area. The peak forecast for the winter 1980-81 is 4,666 megawatts. This represents a growth of 7.8 percent above the previous winter season, and 1.2 percent above the peak of 1978-79. The unusually mild winter of 1979-80 contributed to the small increase in 1979-80.

Planned capability to meet the coming winter peak load is 6,891 megawatts. No major additions of capacity are planned prior to the coming winter season. Zimmer No. 1, the first nuclear unit to be installed in the region, is scheduled for January 1981 and has not been included as available for the peak period.

Almost 83 percent of the current capability is coal-fired capacity; the remainder is oil and gas. There are no nuclear facilities in this electric region, at this time.

Capacity out for scheduled maintenance over the past three winter seasons averaged 795 megawatts and forced outages and unavailable capacity averaged 1,371 megawatts. Forecasted

scheduled maintenance for the coming winter season is 155 megawatts. The three-year average forced outage is included in Table 1.1 line 17, as representative of the forced outage and unavailable capability that could occur for CD.

The CD region has no contracts for scheduled transfers of power with systems in reliability councils adjoining ECAR; however, some intra-regional contracts exist.

As indicated in Table 1.1 for the winter 1980-81, the CD region's planned reserves of 47.7 percent and possible available reserves of 46.1 percent, respectively, appear adequate for the coming season. If the forecasted forced outage rate actually occurs, the actual reserves would be 16.7 percent.

For the 1980-81 winter season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no stability problems.

Michigan Electric Coordinated Group (MECS)
Electric Region 18
(See Table 1.1)

The Michigan Electric Coordinated Group (MECS) is projected to have a noncoincident winter peak demand of 10,892 MW. This is 1.2 percent above the actual winter 1979-80 demand (10,764 MW) and is down 3.5 percent from that forecasted in spring 1980. The load in winter 1979-80 was 4.9 percent lower than the winter 1978-79 load. From the 1977-78 winter period to that of 1979-80, the load decreased by 1.3 percent. The economic condition of the area is greatly dependent upon the auto industry and has been depressed for the last several years, partly accounting for the decrease in load.

The planned installed capability is 17,608 MW. There is no additional major capacity planned for installation during the winter period. The planned reserve margin is 6,716 MW, or 61.7 percent. Net power transfer of 657 MW out of the region reduces the margin to 6,059 MW, or 55.6 percent. There is 383 MW of maintenance scheduled during the winter period and 943 MW of capacity unavailable because of environmental constraints or for other reasons. This reduces the available reserve to 4,733 MW, or 43.5 MW. Forced outages during the 1977-79 winter periods averaged 2,549 MW. If the same magnitude of outages were to occur this winter, the actual reserve would be 2,184 MW, or 20.1 percent. This should be adequate to cover any unforeseen contingencies.

Kentucky Group
Electric Region 15
(See Table 1.1)

The Kentucky Group is projected to have a noncoincident winter peak demand of 5,858 MW. This is 16.2 percent above the actual winter 1979-80 demand (5,040 MW) and is 1.5 percent greater than forecasted in spring 1980. The projection appears to be unusually high, as there was no load growth in the 1980 winter period compared with the 1979 winter period. The load grew only 1.4 percent during the 1977-79 winter periods. If the projected peak is higher than that which does occur, the reserve margin will be greater than shown in Table 1.

The planned installed capability is 7,052 MW. This includes the Big River Electric Corporation's Green No. 2 coal-fired unit (210 MW) planned for completion in December 1980. The planned reserve margin is 1,194 MW, or 20.4 percent. Net power transfer of 1,238 MW into the region increases the margin to 2,432 MW, or 41.5 percent. There is no maintenance scheduled during the period and no capability which is expected to be unavailable. Forced outages during the 1977-79 winter periods averaged 832 MW. If the same magnitude of outages were to occur this winter, the actual reserve would be 1,600 MW, or 27.3 percent. This should be adequate for coverage of unforeseen contingencies.

Indiana Group
Electric Region 16

The Indiana Group is projected to have a noncoincident winter peak demand of 9,200 MW. This is 17.2 percent above the actual winter 1979-80 demand (7,852 MW), but down 2.2 percent from that forecasted in spring 1980. The projection appears to be unusually high considering that there was a negative 5.3 percent growth in the 1980 winter period compared with the 1979 winter period. The load growth during the 1977-79 winter periods was a negative 2.0 percent. If the projected peak is higher than that which does occur, the reserve margin will be greater than shown in Table 1.

The planned installed capability is 11,905 MW. There is no additional major capacity planned for installation during the winter period. The planned reserve margin is 2,705 MW, or 29.4 percent. Net power transfer of 277 MW out of the region reduces the margin to 2,428 MW, or 26.4 percent. There is 816 MW of maintenance scheduled and 236 MW of other unavailable capacity during the period. This reduces the available reserve to 1,376 MW or 15.0 percent. Forced outages during the 1977-79 winter periods averaged 1,588 MW. If the same magnitude of outages were to occur this winter, the actual reserve would be a negative 212 MW, or a minus 2.3 percent. There appears to be enough unused capability in the ECAR region to provide emergency transfers to the region, if required.

TABLE 1.1

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

MW OR PERCENT	Allegheny Power Sys- tems (APS)	American Electric Power Group (AEP) ^{4/}	Central Area Power Coordina- tion Group (CAPCO)	Cincinnati Dayton Group (CD) ^{3/ 4/}	Kentucky Group	Indiana Group	Michigan Electric Coordina- ted Group (MECS)	Total ECAR ^{2/} Region
1. Planned Capability	7587	25625	15641	6891	7052	11905	17608	92309
2. Peak Demand	5260	17397	10954	4666	5858	9200	10892	64227
3. Planned Reserves (1-2)	2327	8228	4687	2225	1194	2705	6716	28082
4. Planned Reserves (X) (3/2) x 100X	44.2	47.3	42.8	47.7	20.4	29.4	61.7	43.7
5. Net Transactions (Imports - Exports)	458	-1156	479	82	1238	-277	-657	167
6. Total Capability (1+5)	8045	24469	16120	6973	8290	11628	16951	92476
7. Total Reserves (6-2)	2785	7072	5166	2307	2432	2428	6059	28249
8. Total Reserves (X) (7/2) x 100X	52.9	40.7	47.2	49.4	41.5	26.4	55.6	44.0
9. Scheduled Maintenance	1052	2051	1015	155	0	816	383	5472
10. Capability After Maintenance (6-9)	6993	22418	15105	6818	8290	10812	16568	87004
11. Reserves After Maintenance (10-2)	1733	5021	4151	2152	2432	1612	5676	22777
12. Reserves After Maintenance (X) (11/2) x 100X	32.9	28.9	37.9	46.1	41.5	17.5	52.1	35.5
13. Inoperable Capability ^{1/}	0	0	0	0	0	236	943	1179
14. Available Capability (10-13)	6993	22418	15105	6818	8290	10576	15625	85825
15. Available Reserves (14-2)	1733	5021	4151	2152	2432	1376	4733	21598
16. Available Reserves (X) (15/2) x 100X	32.9	28.9	37.9	46.1	41.5	15.0	43.5	33.6
17. Forced Outages ^{5/}	2218	3530	4337	1371	832	1588	2549	16425
18. Actual Capability After Forced Outages (14-17)	4775	18888	10768	5447	7458	8988	13076	69400
19. Actual Reserves (18-2)	-485	1491	-186	781	1600	-212	2184	5173
20. Actual Reserves (X) (19/2) x 100X	-9.2	8.6	-1.7	16.7	27.3	-2.3	20.1	8.1

^{1/} Inoperable capacity is that which is out of service for lack of fuel or manpower, or has been deactivated and could require several weeks to be put on line.

^{2/} All liaison member systems have been incorporated with appropriate bulk power member systems for the purposes of this report.

^{3/} Hamilton Municipal (OH) is not included in the reporting. They have not filed a report in 1980.

^{4/} Columbus & Southern Ohio Electric Company is now included in the AEP Group. Previously it was included with Cincinnati-Dayton

^{5/} Three year average.

TABLE 1A.1

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
ALLEGHENY POWER SYSTEM (APS)

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
JAN. 1978	1195	23.1	3359	64.9	4554	88.0
FEB. 1979	0	0.0	1308	24.5	1308	24.5
FEB. 1980	186	3.5	1987	37.7	2173	41.2
3-YR. AVERAGE	460	8.9	2218	42.4	2678	51.2

TABLE 1D.1

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
AMERICAN ELECTRIC POWER GROUP (AEP)

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
JAN. 1978	1283	6.5	4953	29.3	6236	36.9
JAN. 1979	644	3.6	2815	15.9	3459	19.5
FEB. 1980	1921	12.0	2822	17.6	4743	29.7
3-YR. AVERAGE	1283	7.4	3530	20.9	4813	28.7

TABLE 1C.1

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
JAN. 1978	656	6.3	5163	49.9	5819	56.3
JAN. 1979	1075	9.9	5622	51.9	6697	61.8
JAN. 1980	2353	22.5	2227	21.3	4580	43.9
3-YR. AVERAGE	1361	12.9	4337	41.0	5699	54.0

2. ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT) (Electric Region 23)

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 eight 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.

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 and West Corporation (CSW) has petitioned the Federal Energy Regulatory Commission (FERC) to order ERCOT to interconnect with the Southwest Power Pool Reliability Council. As a result of this petition, systems in ERCOT and SPP have signed an interconnection agreement which has not yet been approved by FERC. The agreement calls for construction of two direct current tie lines, one in East Texas and one from Oklahoma into West Texas. Consummation of this interconnection will have some effect on the load and supply situation in future years.

The data in Table 2.1 is a summation of that reported by utilities responding to FERC Form 12E-2 for September 1980. Forced outages, which are not projected by the utilities, have been estimated by DOE using a historical three year winter peak average (See line 17 of Table 2.1). This average includes inoperable capability as well as forced outages. Inoperable capability can be very high in the ERCOT area due to a high dependence upon natural gas for generation; during the winter month utilities experience gas supply cutbacks in favor of home heating use. The historical figure used to derive line 17 is 15.5 percent. The actual reserve margin, which includes the effect of the 15.5 percent forced outage and maintenance outages of 6,423 MW, amounts to 34.5 percent. The maintenance outages projected by the utilities are 14.9 percent of planned capability which compares closely to the three-year winter historical average of 16.1 percent.

The winter capacity availability appears adequate to supply planned load. An oil cut-off would have a very slight effect upon reliability due to ERCOT's low dependence on oil (only 2.31 percent of generation supply by oil in 1979).

TABLE 2.1

ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

<u>MW OR PERCENT</u>	<u>TEXAS INTERCONNECTED SYSTEMS GROUP (TIS)</u>
1. PLANNED CAPABILITY	43062
2. PEAK DEMAND	22424
3. PLANNED RESERVES (1-2)	20638
4. PLANNED RESERVES (%) (3/2)x100	92.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	194
6. TOTAL CAPABILITY (1+5)	43256
7. TOTAL RESERVES (6-2)	20832
8. TOTAL RESERVES (%) (7/2)x100	92.9
9. SCHEDULED MAINTENANCE	6423
10. CAPABILITY AFTER MAINTENANCE (6-9)	36833
11. RESERVES AFTER MAINTENANCE (10-2)	14409
12. RESERVES AFTER MAINTENANCE (%) (11/2)x100	64.3
13. INOPERABLE CAPABILITY <u>1/</u>	2459
14. AVAILABLE CAPABILITY (10-13)	34374
15. AVAILABLE RESERVES (14-2)	11950
16. AVAILABLE RESERVES (%) (15/2)x100	53.3
17. FORCED OUTAGES <u>2/</u>	4215
18. ACTUAL CAPABILITY AFTER FORCED OUTAGES (14-17)	30159
19. ACTUAL RESERVES (18-2)	7735
20. ACTUAL RESERVES (%) (19/2)x100	34.5

1/ INOPERABLE CAPABILITY IS THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE.

2/ FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL THREE AVERAGE AT THE TIME OF THE WINTER PEAK BEGINNING WITH THE 1977-78 WINTER.

3. Mid-Atlantic Area Coordination Council (MAAC)
Pennsylvania-New Jersey-Maryland Interconnection (PJM)
Electric Region 5

The Mid-Atlantic Area Council Region (MAAC) is operated on a "one system" basis under the Pennsylvania-New Jersey-Maryland Interconnection (PJM) pooling agreement.

PJM coordinates the bulk power supply of its eleven investor-owned utility members, and the municipals, electric cooperatives, and small investor-owned electric systems in the MAAC region through associate membership. The MAAC region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia.

The PJM peak load forecast for the winter season 1980-81 is 29,440 megawatts (See Table 3.1). This reflects a 5.2% increase over the actual peak of the previous winter. The 1979-80 peak was almost 600 megawatts lower than the previous winter peak, due primarily to the unusually mild winter in 1979-80.

As a result of heavy air conditioning loads, PJM is traditionally a summer peaking area, and the 1980-81 winter forecast peak is about 85% of the 1980 summer peak. The winter peak can occur in any winter month as it is weather-sensitive.

Planned capability to meet the 1980-81 winter peak load forecast is 47,703 megawatts. Included in the planned capability is the effect of 400 megawatts of new capacity and retirements of 64 megawatts.

The Indian River coal-fired Unit No. 4 went commercial at a reduced rating of 375 megawatts on October 1, 1980. The unit will be uprated to full 400 megawatt capability prior to the winter peak season. Salem No. 2, a 1114 megawatt nuclear unit originally scheduled for installation in October has been delayed until January 1981 and therefore has not been included as available for the winter season.

Coal-fired generation represented 56% of the total energy produced in January 1980 while oil and gas-fired generation combined represented 28%, and nuclear fueled capacity 14%. Table 3.2 indicates projected generation by fuel type for January 1981 based on ERA-Form 160. Table 3.3 provides fuel-use projections for oil and gas for January 1981 and actual use for January 1980. The slow growth in the peak requirements and an actual decline between winter 1978-79 and winter 1979-80 indicates a decreased need for new peaking capacity in the immediate future. The loss of the Three Mile Island nuclear units has increased PJM dependence on older, higher cost capacity, and made it economically advantageous to import short-term firm energy from neighboring pools.

PJM has scheduled firm receipts from Safe Harbor Water Power Corporation of 228 megawatts and 50 megawatts from the Allegheny Power System at the time of the forecast peak load.

Table 3.4 shows the average generating capacity unavailable at the time of the winter peak for the past three winters and the three-year average. The diversity between the summer and winter peaks allows the scheduling of maintenance during the winter season. The three-year scheduled maintenance average (4086 megawatts) is slightly less than that forecasted by PJM for winter 1980-81 (4392 megawatts). The three-year average forced outage in megawatts (7426 MW), from Table 3.4, is included on line 17 of Table 3.1 as representative of the forced outages and unavailable capability that may occur on the PJM system.

As indicated on Table 3.1 for winter 1980-81, the MAAC region will have adequate reserves to meet load responsibility. The 62.0 percent planned reserve is well above the PJM agreement criterion of 22 percent for planned reserves. With allowance for possible total outages of 11,818 MW, MAAC would still have an actual reserve of 22.8%.

Although there is adequate reserve in the MAAC region, the transmission system lacks reserve capacity for large-scale economy transfers without adversely affecting the reliability for emergency interchange. This has created some operational

problems related to voltage and reactive limitations on internal MAAC transmission. Load flow studies and on-line reactive contingency analyses are being undertaken by PJM to find a remedy for this situation.

Critical transmission lines for the near term period, which would have provided relief for the transmission problems if they were in operation, include the delayed Hosensack-Elroy 500 Kv line presently under construction, now scheduled for completion in May 1981, and the Baltimore-Washington 500 Kv loop, which is still in litigation.

Fig. 3.1 indicates the non-simultaneous emergency transfer capabilities between reliability councils for 1980, the number of inter-regional transmission lines 345 Kv and higher, and firm power scheduled at the time of the MAAC winter peak.

There are no Electric Region subdivisions of MAAC.

Table 3.1

MID ATLANTIC AREA COUNCIL (MAAC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

	PENNSYLVANIA NEW JERSEY MARYLAND INTERCONNECTION (PJM)	TOTAL MAAC[2] REGION
1. PLANNED CAPABILITY (MW)	47703	47703
2. PEAK DEMAND (MW)	29440	29440
3. PLANNED RESERVES (MW) (1-2)	18263	18263
4. PLANNED RESERVES (%) (3/2) X 100	62.0	62.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	278	278
6. TOTAL CAPABILITY (MW) (1+5)	47981	47981
7. TOTAL RESERVES (MW) (6-2)	18541	18541
8. TOTAL RESERVES (%) (7/2) X 100	63.0	63.0
9. SCHEDULED MAINTENANCE (MW)	4392	4392
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	43589	43589
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	14149	14149
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	48.1	48.1
13. INOPERABLE CAPABILITY (MW) [1]	0	0
14. AVAILABLE CAPABILITY (MW) (10-13)	43589	43589
15. AVAILABLE RESERVES (MW) (14-2)	14149	14149
16. AVAILABLE RESERVES (%) (15/2) X 100	48.1	48.1
17. FORCED OUTAGES (MW) [3]	7426	7426
18. ACTUAL CAPABILITY AFTER FORCED OUTAGES (MW) (14-17)	36163	36163
19. ACTUAL RESERVES (MW) (18-2)	6723	6723
20. ACTUAL RESERVES (%) (19/2) X 100	22.8	22.8

3.5

[1] INOPERABLE CAPACITY IS THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE.

[2] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

[3] THREE YEAR AVERAGE UNAVAILABLE CAPABILITY EXCLUDING SCHEDULED MAINTENANCE.

Table 3.2
Projected Generation By Fuel Type For January 1981
Mid Atlantic Area Council

<u>FUEL TYPE</u>	<u>GENERATION (MWH)</u>	<u>% OF TOTAL</u>
HYDRO	284,045	1.8
COAL	8,691,273	55.6
GAS	84,531	0.5
OIL	3,449,911	22.1
NUCLEAR	3,186,747	20.4
PUMPED STORAGE (NET)	(55,278)	(0.4)
TOTAL	15,641,229	100.0

() indicates negative number

Table 3.3
Oil and Gas Use Projection for January 1981
and
Oil and Gas Actual Use for January 1980
Mid Atlantic Area Council

<u>FUEL TYPE</u>	<u>JAN. 1981 PROJECTION</u>	<u>JAN. 1980 ACTUAL</u>	<u>% CHANGE 1-81/1-80</u>
Gas (MCF)	1,059	2,485	-57.4
Oil (BBLS)	6,063,780	6,887,338	-12.0

Table 3.4
Average Generating Capacity Unavailable at the Time of the
Winter System Peak Demand 1977-1978, 1978-1979, 1979-1980
Mid Atlantic Area Council

<u>MONTH-YEAR</u>	<u>SCHEDULED MAINTENANCE</u>		<u>FORCED OUTAGES</u>		<u>TOTAL UNAVAIL.</u>	
	<u>(MW)</u>	<u>(%) OF PEAK</u>	<u>(MW)</u>	<u>(%) OF PEAK</u>	<u>(MW)</u>	<u>(%) OF PEAK</u>
Jan. 1978	2,154	7.7	8,739	31.2	10,893	38.9
Feb. 1979	4,689	16.4	4,623	16.2	9,312	32.6
Feb. 1980	5,414	19.4	8,917	31.9	14,331	51.3
3-Yr. Average	4,086	14.5	7,426	26.4	11,512	40.9

50 -> FIRM POWER TRANSFER IN MEGAWATTS
 1-500 NUMBER OF INTERCONNECTIONS AND KILOVOLTS
 3000--> EMERGENCY TRANSFER CAPABILITY
 ----- NO PHYSICAL CONNECTION BETWEEN COUNCILS
 WITHIN THE UNITED STATES

TRANSFER CAPABILITY BETWEEN MAAC AND ADJACENT COUNCILS

FIGURE 3.1

3.8

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4. MID-AMERICA INTERPOOL NETWORK (MAIN) (See Table 4.1)

The MAIN region includes all of the state of Illinois and parts of Wisconsin, Michigan and Missouri. The region is subdivided, for purposes of this report, into Electric Region 6, Commonwealth Edison Company (ER 6-CECO); Electric Region 17, Illinois-Missouri Group (ER 17-ILLMO); and Electric Region 19, Wisconsin-Upper Michigan Systems Group (ER 19-WUMS).

The non-coincident winter peak load of the MAIN region is projected to be 27,373 MW. This is 3.3 percent greater than the actual winter 1979-80 demand (26,511 MW) and is reduced 348 MW, or 1.3 percent from the forecast made in Spring, 1980. Most of the reduction in the forecast occurs in Electric Region 6, Commonwealth Edison Company area. During the winter period 1977-79 the region showed essentially no growth in peak demand.

The planned installed capability is estimated to be 42,644 MW. No major new capacity is scheduled to be completed during the winter period. The planned reserve margin is forecasted to be 15,271 MW, or 55.8 percent of the projected peak demand. Net power transfer of 702 MW out of the region reduces the margin to 14,569 MW, or 53.2 percent. Allowance for scheduled maintenance of 3069 MW and other unavailable capability of 21 MW further reduces the available margin to 11,479 MW, or 41.9 percent. Forced outages during the 1977-79 winter periods averaged 8983 MW. If forced outages of this magnitude were to occur this winter, the actual reserve would be 2496 MW or 9.1 percent. The data shown in line 17 of Table 4 include the removal of the Commonwealth Edison Company's two Powerton units (1700 MW) from service for the winter season, due to a coal dust fire and explosion at the plant on October 14, 1980.

Commonwealth Edison Company Electric Region 6

Within the MAIN region, Electric Region 6 (Commonwealth Edison Company) is projected to have a winter peak demand of 10,780 MW. This is only 0.6 percent above the actual winter 1979-80 demand (10,715 MW) and is reduced 360 MW or 3.2 percent from the forecast made in Spring, 1980. During the 1977-79 winter periods the area showed essentially no growth in peak demand.

The planned installed capability of 18,241 MW results in a planned reserve margin of 7461 MW, or 69.2 percent of the expected peak demand. No power transactions with other utilities are planned during the period. Planned scheduled maintenance amounts to 1294 MW, resulting in an available reserve margin after maintenance of 6167 MW, or 57.2 percent. However, the installed

capability includes the two Powerton units (1700 MW) which were taken out of service in October. These units are not expected to be back in service during the winter peak period; their capacity is included in the forced outage capacity of line 17 in Table 4.1. The actual Forced Outages over the 1977-79 winter periods varied from 6481 MW to 7163 MW, with an average outage of 6259 MW. If the forced outages which occur this winter approximate the average which occurred over the past three years, the actual reserve margin would be a negative 92 MW, or -0.9 percent. There is expected to be enough other capability available within MAIN to supply emergency power, if necessary. In addition, some of the capacity planned for maintenance possibly could be delayed, if required.

Illinois-Missouri Group (ILLMO) Electric Region 7

The ILLMO region (Electric Region 17) is projected to have a non-coincident winter peak demand of 10,224 MW. This is 7.7 percent above the actual winter 1979-80 demand (9496 MW) and is essentially the same as forecasted in Spring, 1980. The projection may be on the high side, as the load had a negative growth of 0.7 percent during the 1977-79 winter periods. However, if the actual peak is lower than that which is projected, the reserve margin will be greater than shown.

The planned installed capability of 15,839 MW results in a planned reserve margin of 5615 MW, or 54.9 percent. Net power transfers of 845 MW out of the region reduces the margin to 4770 MW, or 46.7 percent. Allowance for scheduled maintenance of 1063 MW and other unavailable capability of 21 MW further reduces the available reserve to 3686 MW, or 36.1 percent. Forced outages during the previous winter periods (1977-79) averaged 2095 MW. If forced outages of this magnitude were to occur this winter, the actual reserves would be 1591 MW, or 15.6 percent. This should be adequate to cover other contingencies should they occur.

Wisconsin-Upper Michigan Systems (WUMS) Electric Region 19

The WUMS region (Electric Region 19) is projected to have a non-coincident peak demand of 6369 MW. This is only 1.1 percent above the actual winter 1979-80 demand (6300 MW) and is slightly less than the 6385 MW forecasted in Spring, 1980. The winter peak demand during the 1977-79 period actually grew at a rate of 2.5 percent. One reason the load in this region is not expected to increase much is because of the sluggish economic conditions in the region, particularly in the Upper Michigan mining industry.

The planned installed capability of 8564 MW results in a planned reserve margin of 2195 MW, or 34.5 percent. Net power transfers of 143 MW into the region increases the margin to 2338 MW, or 36.7 percent. Allowance for scheduled maintenance of 712 MW reduces the margin to 25.5 percent. Forced outages during the period 1977-79 averaged 629 MW. If the same magnitude of outages were to occur this winter, the actual reserve would be 997 MW, or 15.7 percent. This should be adequate for coverage of unforeseen contingencies.

TABLE 4.1

MID-AMERICA INTERPOOL NETWORK (MAIN)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

MW OR PERCENT	Common- Wealth Edison (CECO)	Illinois- Missouri Group (ILLMO)	Wisconsin- Upper Mich. Systems Group (WUMS)	Total MAIN Region
1. Planned Capability	18241	15839	8564	42644
2. Peak Demand	10780	10224	6369	27373
3. Planned Reserves (1-2)	7461	5615	2195	15271
4. Planned Reserves (X) (3/2) x 100%	69.2	54.9	34.5	55.8
5. Net Transactions (Imports - Exports)	0	-845	143	-702
6. Total Capability (1+5)	18241	14994	8707	41942
7. Total Reserves (6-2)	7461	4770	2338	14569
8. Total Reserves (X) (7/2) x 100%	69.2	46.7	36.7	53.2
9. Scheduled Maintenance	1294	1063	712	3069
10. Capability After Maintenance (6-9)	16947	13931	7995	38873
11. Reserves After Maintenance (10-2)	6167	3707	1626	11500
12. Reserves After Maintenance (X) (11/2) x 100%	57.2	36.3	25.5	42.0
13. Inoperable Capability ^{1/}	0	21	0	21
14. Available Capability (10-13)	16947	13910	7995	38852
15. Available Reserves (14-2)	6167	3686	1626	11479
16. Available Reserves (X) (15/2) x 100%	57.2	36.1	25.5	41.9
17. Forced Outages	6259	2095	629	8983
18. Actual Capability After Forced Outages (14-17)	10688	11815	7366	29869
19. Actual Reserves (18-2)	-92	1591	997	2496
20. Actual Reserves (X) (19/2) x 100%	-0.9	15.6	15.7	9.1

^{1/} Inoperable capacity is that which is out of service for lack of fuel or manpower, or has been deactivated and could require several weeks to be put on line.

^{2/} Forced outages are calculated using the historical three year average at the time of the winter peak beginning with the 1977-78 winter.

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5. MID-CONTINENT AREA RELIABILITY
COORDINATION AGREEMENT (MARCA)
(See Table 5.1)

The United States portion of MARCA includes all of the states of Iowa, Minnesota, Nebraska, North Dakota and portions of Illinois, Montana, South Dakota and Wisconsin. The Mid-Continent Area Power Pool (MAPP) coordinates the planning of bulk power supply and daily operations of essentially all major utilities in the MARCA area. The Manitoba (Canada) Hydroelectric Board (MHEB) is an associated member of MARCA; however, its generating resources and loads have not been included in this report, except to the extent of firm transactions with MARCA members. Two 230-Kilovolt ties between Manitoba Hydro and the MARCA transmission network could provide emergency support to the United States systems if capacity is available in Manitoba. A new 500 kV line between Manitoba and MARCA systems was energized in May, 1980, which can provide additional emergency support.

A study conducted by the MAPP Operating Committee indicates that due to low water conditions in Manitoba, import from MHEB into MARCA could become limited. The study also indicates import limitation due to heavy loading on the St. Joseph - Maryville 161 kV line. The limiting conditions described by the report, however will not have adverse impact on the MARCA system due to the sufficient reserve anticipated for this winter.

The MARCA Region is projected to have a non-coincident winter peak demand of 16,834 MW. This is 9.0 percent above the actual winter 1979-80 demand (15,445 MW) but is 2.8 percent below that forecasted in spring, 1980. The load showed essentially no growth during the 1977-79 winter periods. Hence, the projected peak would appear to be on the high side. If the actual peak is lower than that which is expected the reserve margin will be greater than shown in Table 5.1.

The planned installed capability is 25,394 MW. This includes 223 MW of the Coal Creek No. 2 generating unit scheduled for operation in November, 1980. The Ottumwa No. 1 unit (675 MW) planned for operation in January 1981 is not included in the planned capability. The planned reserve margin is 8560 MW, or 50.8 percent. Net power transfer of 493 MW out of the region reduces the margin to 8,067 MW, or 47.9 percent. There is 198 MW of scheduled maintenance and 24 MW of other unavailable capacity during the period. This reduces the available reserves to 7,845 MW, or 46.6 percent. Forced outages during the 1977-79 winter periods averaged 1,935 MW. If the same magnitude of outages were to occur this winter, the actual reserve would be 5,910 MW, or 35.1 percent. This should be more than adequate for coverage of unforeseen contingencies.

TABLE 5.1**MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)****TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD**

MM OR PERCENT	Total MARCA Region
1. Planned Capability	25394
2. Peak Demand	16834
3. Planned Reserves (1-2)	8560
4. Planned Reserves (X) (3/2) x 100%	50.8
5. Net Transactions (Imports - Exports)	-493
6. Total Capability (1+5)	24901
7. Total Reserves (6-2)	8067
8. Total Reserves (X) (7/2) x 100%	47.9
9. Scheduled Maintenance	198
10. Capability After Maintenance (6-9)	24703
11. Reserves After Maintenance (10-2)	7869
12. Reserves After Maintenance (X) (11/2) x 100%	46.7
13. Inoperable Capability ^{1/}	24
14. Available Capability (10-13)	24679
15. Available Reserves (14-2)	7845
16. Available Reserves (X) (15/2) x 100%	46.6
17. Forced Outages ^{2/}	1935
18. Actual Capability After Forced Outages (14-17)	22744
19. Actual Reserves (18-2)	5910
20. Actual Reserves (X) (19/2) x 100%	35.1

^{1/} Inoperable capacity is that which is out of service for lack of fuel or manpower, or has been deactivated and could require several weeks to be put on line.

^{2/} Forced outages are calculated using the historical three average at the time of the winter peak beginning with the 1977-78 winter.

6. Northeast Power Coordinating Council (NPCC)
Electric Regions 3 and 4

The Northeast Power Coordinating Council (NPCC) consists of twenty-one utility member systems located in New England, New York, Ontario and New Brunswick. There are four planning and operating entities or subregions -- two in the United States and two in Canada. This report addresses only the two subregions in the United States' portion of the Council, the New England Power Pool (NEPOOL) and the New York Power Pool (NYPP).

The NPCC non-coincident peak load forecast for the winter season 1980-81 as shown on line 2 of Table 6.1 is 36,098 megawatts. This reflects a 3.8 percent increase over the actual peak of the previous winter, and a 4.0 percent increase over the winter peak of 1978-79. The peak of 1979-80 winter season was low due to the unusually mild winter. NEPOOL is a winter peaking system, while NYPP is a summer peaking group. There is little inter-pool diversity but each pool takes advantage of intra-system diversity in establishing its reserve criteria.

Planned capability to meet the 1980-81 winter peak load forecast is 52,510 megawatts. There are no major generating additions scheduled for installation during the winter peak period.

All areas of NPCC remain dependent on oil for the production of electric energy. This heavy dependence on oil adversely impacts both the cost and adequacy of electric power supply. Oil-fired generation represented 51% of the total energy produced in January 1980; nuclear generation 20%; hydro 16%; coal 11%; and gas and other sources 2%. Table 6.1 indicates projected generation by fuel type for January 1981 based on ERA Form 160. Table 6.2 provides projected generation by fuel type for January 1981. Table 6.3 compares actual use of gas and oil in January 1980 with the projected use of those fuels for January 1981. NPCC has not scheduled any firm inter-regional receipts or deliveries for the forecast period.

Table 6.4 shows the average generating capacity unavailable at the time of the winter peak for the past three winters, and the three year average. The diversity between the seasonal peaks of each regional area allows for scheduling of maintenance during the appropriate season.

The three-year scheduled maintenance average was 3994 MW as compared to the sum of the individual company forecasts in the Form 12E-2 Reports of 2247 MW (line 9 of Table 6.1).

The three-year average forced outage for NYPP in megawatts as shown in Table 6.1 line 17 is representative of the forced outages and unavailable capability that may occur on the NYPP system. The NEPOOL forecast, 3300 megawatts, as reported in FPC Form 12E-2, is slightly higher than the three-year NEPOOL average of 3222 megawatts.

As indicated on Table 6.1 for winter 1980-81, the NPCC region will have adequate reserves to meet its load responsibility. The 18.3 percent reserves after all projected outages is well above the NPCC required reserves. Total forecasted reserves are 45.5%, before effect is given to possible outages and the net of imports and exports.

There are no major transmission lines scheduled for completion for the 1980/1981 peak. The transmission system is adequate to cover load commitments for the period with no stability problem areas.

The Electric Regions within NPCC are New England Power Pool (NEPOOL) New York Power Pool (NYPP); these are discussed separately below.

New York Power Pool

The New York Power Pool (NYPP) coordinates the planning and operation of the eight major electric utility companies in New York State.

The state of New York is a summer peak area. Although the northern portion of the state peaks during the winter the larger loads of the downstate utilities swing the over-all state peak to summer. The peak forecast for the winter 1980-81 is 20,023 megawatts. This is a 2.7% increase over the previous winter and 9% lower than the summer peak. Winter peak growth in NYPP has been depressed over the last three years reflecting the mild winter in 1979-80 and also depressed economic growth.

Planned capability to meet the coming winter peak load is 31,412 megawatts. No major additions of capacity are expected within the winter season. New York, while not being quite as dependent on fuel oil as New England, generated 41% of its electric energy, from oil in January 1980. Hydro-electric capacity, the bulk from the St. Lawrence and Niagara projects of the Power Authority of the State of New York, represented 24% of January 80 generation. Nuclear and coal fired generation were 16% and 19% respectively.

Table 6B.1 provides projected generation by fuel type for January 1981 based on ERA-Form 160. Table 6B.2 compares actual 1980 (January) use of oil and gas with projected 1981 (January) use of those fuels. Contrary to other regional projections, oil-fired generation is expected to increase and coal-fired generation will decrease for the month of January 1981. These unusual shifts in fuel use are due in part to the completion of the oil-fired Oswego Unit No. 6 (850 MW) in August 1980, and unusual maintenance requirements on Niagara Mohawk's Dunkirk and Huntley coal-fired units amounting to approximately 200 MW maintenance outage daily. However, use of fuel oil for the past three years has generally decreased in the NYPP.

Table 6B.3 shows the actual generating capacity unavailable at the time of the winter peak for the past three winters and the three year average. Scheduled maintenance over the past three winter seasons averaged 2876 megawatts and forced outages averaged 4533 megawatts. At the time of the 1980/81 peak, scheduled maintenance (the sum of the individual company projections), as shown in Table 6.1 for the NYPP, is projected to be 2005 megawatts.

As indicated on Table 6.1 for winter 1980-81, the NYPP region should have actual reserves of about 22.9%, which is adequate to meet the load responsibility. The NYPP reserve criterion calls for a planned pool reserve of 18%; present forecasts indicate a planned reserve of 56.9% before effect is given to the net of imports and exports and to possible outages of capacity.

The recent accident at Indian Point No. 2 Nuclear Unit, salt water intrusion into the reactor vessel, will make the unit unavailable for service during the winter peak period. The effect of this unit's unavailability has been included in the total of forced outages on line 17 of Table 6.1.

The New York Power Pool continues to experience transmission bottle necks during off-peak periods in the Utica Albany area as a result of commercial operation of Oswego Unit No. 6, and Ontario Hydro imports.

New England Power Pool (NEPOOL)
Electric Region 3

NEPOOL is the operating pool for over forty privately and publicly owned utilities operating in the six New England States.

NEPOOL is a winter peak area; the peak load forecast for winter 1980-81 is 16,075 megawatts. This is a 5.2% increase over the actual peak of the previous winter. The growth of the 1979-80 peak over the preceding winter was only 1.4%, due primarily to the unusually mild winter in 1979-80. The two year average annual growth would be 3.3%, more in line with recent trends.

Planned capability to meet the 1980-81 winter peak load forecast is 21,098 megawatts. No new generating capacity is expected to be available for the winter peak season.

A major portion of the NEPOOL generation is oil-fired and represented 63% of the energy generated in January 1980, while nuclear-fueled generation represented 25%. Table 6A.1 indicates projected generation by fuel type for January 1981 based on ERA-Form 160. Table 6A.2 provides fuel use projections for oil and gas for January 1981 and actual use for January 1980. Table 6A.3 shows the capacity unavailable at the time of the winter peaks for 1977-78, 1978-79 and 1979-80.

The NEPOOL scheduled maintenance as reported in FPC Form 12E-2 and summarized in Table 6A.3 is 242 MW, below the 1118 MW average. The forecast of forced outages and other unavailable capability is 3300 megawatts and is included in Table 6.1, line 17 as being indicative of the forced outages that might be experienced during the winter season.

As indicated on Table 6.1 for the winter 1980-81, the NEPOOL region will have adequate reserves to meet their load responsibilities. Reserves after maintenance are 5,326 megawatts or 33.1%. After forecasted forced outages actual reserves would be 2026 MW or 12.6%.

TABLE 6.1

NORTHEAST POWER COORDINATING COUNCIL (NPCC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

	NEW ENGLAND POWER POOL (NEPOOL)	NEW YORK POWER POOL (NYPP)	TOTAL NPCC[2] REGION
1. PLANNED CAPABILITY (MW)	21098	31412	52510
2. PEAK DEMAND (MW)	16075	20023	36098
3. PLANNED RESERVES (MW) (1-2)	5023	11389	16412
4. PLANNED RESERVES (%) (3/2) X 100	31.2	56.9	45.5
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	545	-271	274
6. TOTAL CAPABILITY (MW) (1+5)	21643	31141	52784
7. TOTAL RESERVES (MW) (6-2)	5568	11118	16686
8. TOTAL RESERVES (%) (7/2) X 100	34.6	55.5	46.2
9. SCHEDULED MAINTENANCE (MW)	242	2005	2247
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	21401	29136	50537
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	5326	9113	14439
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	33.1	45.5	40.0
13. INOPERABLE CAPABILITY (MW) [1]	0	0	0
14. AVAILABLE CAPABILITY (MW) (10-13)	21401	29136	50537
15. AVAILABLE RESERVES (MW) (14-2)	5326	9113	14439
16. AVAILABLE RESERVES (%) (15/2) X 100	33.1	45.5	40.0
17. FORCED OUTAGES (MW) [3]	3300	4533	7833
18. ACTUAL CAPABILITY AFTER FORCED OUTAGES (MW) (14-17)	18101	24603	42704
19. ACTUAL RESERVES (MW) (18-2)	2026	4580	6606
20. ACTUAL RESERVES (%) (19/2) X 100	12.6	22.9	18.3

6.8

[1] INOPERABLE CAPACITY IS THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE.

[2] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

[3] THREE-YEAR AVERAGE AT TIME OF WINTER PEAK BEGINNING WITH WINTER 1977-78.

TABLE 6.2

**PROJECTED GENERATION BY FUEL TYPE FOR JANUARY 1981
NORTHEAST POWER COORDINATION COUNCIL**

FUEL TYPE	GENERATION (MWH)	% OF TOTAL
HYDRO	2,418,086	14.4
COAL	1,044,900	6.2
GAS	40,150	0.2
OIL	9,759,462	57.9
NUCLEAR	3,705,277	22.0
PUMPED STORAGE (NET)	(136,000)	(0.8)
OTHER	11,000	0.1
TOTAL	16,842,875	100.0

TABLE 6.3

**GAS AND OIL USE PROJECTION FOR JANUARY 1981
AND**

**ACTUAL GAS AND OIL USE FOR JANUARY 1980
NORTHEAST POWER COORDINATION COUNCIL**

FUEL TYPE	JAN.1981 PROJECTION	JAN.1980 ACTUAL	% CHANGE 1-81/1-80
GAS (MCF)	551	1,047	-47.4
OIL (BRLS)	16,656,981	14,526,330	14.7

TABLE 6.4

**AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
NORTHEAST POWER COORDINATION COUNCIL**

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
DEC 1977	3443	10.1	6673	19.7	10116	29.8
FEB. 1979	5030	14.5	7460	21.5	12490	36.0
DEC 1979	3509	10.1	9132	26.3	12641	36.4
3-YR. AVERAGE	3994	11.6	7755	22.5	11749	34.1

TABLE 6B.1
PROJECTED GENERATION BY FUEL TYPE FOR JANUARY 1981
NEW YORK POWER POOL

FUEL TYPE	GENERATION (MWH)	% OF TOTAL
HYDRO	2,105,000	22.2
COAL	784,900	8.3
GAS	40,150	0.4
OIL	4,963,722	52.4
NUCLEAR	1,661,700	17.5
PUMPED STORAGE (NET)	(89,000)	(0.9)
OTHER	11,000	0.1
TOTAL	9,477,472	100.0

TABLE 6B.2
GAS AND OIL USE PROJECTION FOR JANUARY 1981
AND
ACTUAL GAS AND OIL USE FOR JANUARY 1980
NEW YORK POWER POOL

FUEL TYPE	JAN. 1981 PROJECTION	JAN. 1980 ACTUAL	% CHANGE 1-81/1-80
GAS (MCF)	551	1,020	-46.0
OIL (BBLS)	8,591,206	6,716,116	27.9

TABLE 6B.3
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
NEW YORK POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
DEC. 1977	1943	10.2	3851	20.2	5794	30.4
FEB. 1979	3278	16.7	4846	24.7	8124	41.4
DEC. 1979	3407	17.6	4902	25.2	8309	42.8
3-YR. AVERAGE	2876	14.8	4533	23.4	7409	38.2

TABLE 6A.1
PROJECTED GENERATION BY FUEL TYPE FOR JANUARY 1981
NEW ENGLAND POWER POOL

FUEL TYPE	GENERATION (MWH)	% OF TOTAL
HYDRO	313,086	4.3
COAL	260,000	3.5
OIL	4,795,740	65.1
NUCLEAR	2,043,577	27.7
PUMPED STORAGE (NET)	(47,000)	(0.6)
TOTAL	7,365,403	100.0

TABLE 6A.2
FUEL USE PROJECTION FOR JANUARY 1981
VS
FUEL USE ACTUAL FOR JANUARY 1980
NEW ENGLAND POWER POOL

FUEL TYPE	JAN. 1981 PROJECTION	JAN. 1980 ACTUAL	% CHANGE 1-81/1-80
GAS (MCF)	0	27	-
OIL (BBLs)	8,065,775	7,810,214	3.3

TABLE 6A.3
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
WINTER SYSTEM PEAK DEMAND 1977-1978, 1978-1979, 1979-1980
NEW ENGLAND POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE		FORCED OUTAGES		TOTAL UNAVAIL.	
	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK	(MW)	(%) OF PEAK
DEC. 1977	1500	10.1	2822	19.0	4322	29.1
FEB. 1979	1752	11.6	2614	17.3	4366	28.9
DEC. 1979	102	0.7	4230	27.7	4332	28.4
3-YR. AVERAGE	1118	7.5	3222	21.3	4340	28.8

6.12

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7. SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)

Introduction

The Southeastern Electric Reliability Council (SERC) region is comprised of four electric regions. Electric Region 7 covers Peninsular Florida and is represented by the Florida Electric Coordinating Group (FCG). Electric Region 9 is referred to as the Southern Company Group Region and its service area covers the Florida Panhandle, the southeastern quadrant of Mississippi, the lower three-fourths of Alabama, and all except a small portion of Georgia. Electric Region 11 is represented by the Tennessee Valley Authority (TVA) Group Region and serves all of Tennessee, the northeastern quadrant of Mississippi, three Cooperatives in North Georgia and Southwestern portion of North Carolina, a small portion of Southwest Kentucky, and the northern quarter of Alabama. The fourth region in SERC is Electric Region 12 and is referred to as the Virginia-Carolinas (VACAR) Group Region and serves South Carolina, all except a small Southwest portion of North Carolina, the Virginia Electric and Power Company's service area in Virginia and three counties in West Virginia.

Demand and Supply

The FCG and TVA regions are winter peaking areas while the Southern and VACAR regions are summer peaking areas. FCG, TVA, and VACAR each have a seasonal peak diversity of less than five percent based on this past summer's record heat and the projected winter 1980-81 peak loads. The 22.6 percent diversity of seasonal peaks in the Southern Company Group is enough to maintain the SERC region as a summer peaking region.

A summary of supply, demand and the relevant factors contributing to the reserve margin, is shown in Table 7.1. The item on Line 17 of Table 7.1, forced outages, was derived from the historical forced outages for the winter 1977-78 through the winter 1979-80 peak month for each region.

Table 7.1
Southeastern Reliability Council (SERC)
Tabulation of Estimated Load and Supply for Winter 1980-81 Peak Period

<u>Mw or Percent</u>	<u>Florida Coordinating Group Region (FCG)</u>	<u>Southern Company Group Region</u>	<u>Tennessee Valley Authority Group (TVA)</u>	<u>Virginia- Carolinas Group Region (VACAR)</u>	<u>Total SERC 2/ Region</u>
(1) Planned Capability	23,684	25,828	28,544	36,224	114,280
(2) Peak Demand	19,090 ^{3/}	17,913	20,952	28,298	86,253
(3) Planned Reserve (1-2)	4,594	7,915	7,592	7,926	28,027
(4) Planned Reserve (%) (3+2) x 100	24.1	44.2	36.2	28.0	32.5
(5) Net Transactions	311	1,949	1,100	958	4,318
(6) Total Capability (1+5)	23,995	27,777	29,644	37,182	118,598
(7) Total Reserve (6-2)	4,905	9,864	8,692	8,884	32,345
(8) Total Reserve (%) (7+2) x 100	25.7	55.1	41.5	31.4	37.5
(9) Scheduled Maintenance	1,968	3,437	689	2,699	8,793
(10) Capability after Maintenance (6-9)	22,027	24,340	28,955	34,483	109,805
(11) Reserve after Maintenance (10-2)	2,937	6,427	8,003	6,185	23,552
(12) Reserve after Maintenance (%) (11+2) x 100	15.4	35.9	38.2	21.9	27.3
(13) Inoperable Capability ^{1/}	0	0	0	0	0
(14) Available Capability (10-13)	22,027	24,340	28,955	34,483	109,805
(15) Available Reserve (14-2)	2,937	6,427	8,003	6,185	23,552
(16) Available Reserve (%) (15+2) x 100	15.4	35.9	38.2	21.9	27.3
(17) Forced Outages (F.O.)	2,408	2,563	4,172	4,927	14,070
(18) Available Capability after F.O. (14-17)	19,619	21,777	24,783	29,556	95,735
(19) Actual Reserve (18-2)	529	3,864	3,831	1,258	9,482
(20) Actual Reserve (%) (19+2) x 100	2.8	21.6	18.3	4.4	11.0

7.2

- ^{1/} Inoperable capacity is that which is out of service for lack of fuel or manpower, or has been deactivated and could require several weeks to be put in line.
- ^{2/} All liaison member systems have been incorporated with appropriate bulk power member systems for the purposes of this report.
- ^{3/} Includes 546 Mw interruptible load.

Table 7.2 provides background data for the foregoing Table 7.1 as well as a three year historic data base for use in evaluating the data projected in Table 7.1.

TABLE 7.2
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME
OF THE WINTER SYSTEM PEAK DEMAND
1977-78 THROUGH 1979-80

SERC Electric Regions	Maintenance Outage		Forced Outage		Total Unavailable	
	Mw	% of Peak	Mw	% of Peak	Mw	% of Peak
Florida	1,838	10.6	2,408	13.8	4,246	24.4
Southern	2,407	14.2	2,563	15.0	4,970	29.2
TVA	1,427	6.7	4,172	19.4	5,599	26.1
VACAR	2,294	8.8	4,927	18.8	7,221	27.6

Fuel Use

Fuel use is a concern in each of the four regions of SERC and particularly so in Peninsular Florida. This will be discussed in more detail in the individual section for each region. Table 7.3 shows the projected generation by fuels for January 1981 for the SERC region.

TABLE 7.3
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
PROJECTED GENERATION BY FUELS FOR JANUARY 1981

<u>Type Fuel</u>	<u>Generation (Mwh)</u>	<u>Percent of Total</u>
Hydro	3,149,107	7.5
Coal	23,743,809	56.5
Gas	733,377	1.7
Oil	4,752,247	11.3
Nuclear	9,405,820	22.4
Other	208,600	0.6
Total	41,992,960	100.0

Table 7.4 compares fuel consumption in January 1980 and the projected consumption in January 1981. Table 7.4 shows that based on the January 1981 projection the natural gas and oil consumption will be reduced by 31.5 and 0.7 percent respectively. This is compatible with the national goal for reduction in consumption of these fuels.

TABLE 7.4
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
FUEL USE PROJECTED FOR JANUARY 1981 VERSUS ACTUAL FOR JANUARY 1980

<u>Fuel Type</u>	<u>January 1981 Projection</u>	<u>January 1980 Actual</u>	<u>Percent Change Jan. '81 vs. Jan. '80</u>
Gas(Mcf)	7,745,000	11,309,128	(31.5)
Oil(BBL)	6,799,641	6,846,474	(0.7)

Transmission

Figure 7.1 shows the SERC Subregional EHV interconnecting lines, maximum transfer capacity and scheduled power transfers for the winter 1980-81 peak load season. All of the scheduled transfers are less than 65 percent of maximum transfer capacity for the forthcoming season. The 65 percent limit is considered satisfactory from the standpoint of balancing economics and reliability.

Table 7.5 summarizes the scheduled power transfers and transmission import capacities for each Electric Region of SERC for the 1980-81 winter peak load situation.

TABLE 7.5
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
SUMMARY OF TRANSMISSION TRANSFERS AND IMPORT CAPACITY
WINTER 1980-81

<u>SERC Subregion</u>	<u>Import Capacity Mw</u>	<u>Scheduled Transfers</u>		<u>Unused Capacity</u>	
		<u>Mw</u>	<u>% of Import Capacity</u>	<u>Mw</u>	<u>% of Peak Demand</u>
Florida	800	400	50	400	2
Southern	5,600	740	13	4,860	26
TVA	7,200	1,100	15	6,100	29
VACAR	5,050	300	6	4,750	17
SERC	9,850	1,460	15	8,390	10

FIGURE 7.1
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
SERC ELECTRIC REGION SCHEDULED POWER TRANSFERS
WINTER 1980-81

Legend

— (2) —	Number of Interconnecting Lines at 500 kv or Higher Voltage
$\frac{250}{2000}$	Scheduled Firm Power Transfer in Mw Maximum Transfer Capability in Mw <u>1/</u>

1/ Based on typical circuit capability of 1,200 Mw per circuit for 500 kv and 250 Mw per circuit for 230 kv. Transmission lines which loop through another organizational area and change ownership but do not include a generating plant are not considered interconnecting lines in this analysis. The FCG-SOU tie includes 115 kv lines.

Florida Coordinating Group (FCG) Region

The FCG region has the heaviest dependence on oil in the SERC area, accounting for 70 percent of the total consumption. Because of this, the nuclear units play an important role in the upcoming winter season as well as the near future as the region explores new methods of reducing oil consumption. Table 7A.1 shows the projected generation by fuel type for January 1981 and Table 7A.2 shows a comparison between fuel use for January 1980 and the projected use for January 1981.

TABLE 7A. 1
FLORIDA COORDINATING GROUP REGION
PROJECTED GENERATION BY FUELS FOR JANUARY 1981

<u>Type Fuel</u>	<u>Generation (Mwh)</u>	<u>Percent of Total</u>
Hydro	0	0
Coal	1,321,400	18.7
Gas	619,109	8.8
Oil	3,331,941	47.2
Nuclear	1,579,020	22.4
Other	<u>208,600</u>	<u>2.9</u>
Total	7,060,070	100.0

TABLE 7A.2
FLORIDA COORDINATING GROUP REGION
FUEL USE PROJECTED FOR JANUARY 1981 VERSUS ACTUAL FOR JANUARY 1980

<u>Fuel Type</u>	<u>January 1981 Projection</u>	<u>January 1980 Actual</u>	<u>Percent Change Jan. '81 vs. Jan. '80</u>
Gas (Mcf)	6,769,000	10,411,440	(35.0)
Oil (Bbls.)	4,522,032	4,481,267	0.9

The 22.4 percent of the total generation produced by nuclear units represents an average capacity factor of about 71 percent. The importance of this contribution becomes apparent by consideration of the loss for the entire month of a 696 Mw nuclear unit replaced by oil-fired generation. This replacement would amount to an additional consumption of about 499,000 barrels of oil or an increase of 12 percent over January 1980. The current limitation of import capability, as shown on Figure 7.1, further restricts any sizable relief from oil usage in the event of the loss of a large non-oil unit.

The demand/supply situation shown on Table 7.1 shows a planned reserve of 24.1 percent, while the actual reserves after applying the historic forced outage rate and maintenance would be about 2.8 percent.

The planned reserves are consistent with reasonable planning practices for the FCG region. The planned scheduled maintenance capability listed in Table 7.1 is reasonable when compared to the historic value in Table 7.2. The winter peak demands in Florida are very weather sensitive, sharp and generally of short duration. It is also noted that the 19,090 Mw peak demand includes 546 Mw of interruptible load.

Southern Company Group Region

The Southern Company Group Region has the greatest energy production by coal as a percent of total production among the SERC Electric Regions. The complete summation of generation by fuel types, shown on Table 7B.1, also indicates in comparison to similar tables for the other regions, that the Southern Company Group Region produces the least nuclear energy in megawatt-hours and as a percent of the total requirements. Although the fuel mix for the region is considered highly desirable in attaining the goals of our national commitment, some consideration should be given to the possible effects of a prolonged curtailment of coal deliveries.

TABLE 7B.1
SOUTHERN COMPANY GROUP REGION
PROJECTED GENERATION BY FUELS FOR JANUARY 1981

<u>Type Fuel</u>	<u>Generation (Mwh)</u>	<u>Percent of Total</u>
Hydro	600,900	7.0
Coal	6,500,260	76.1
Gas	73,138	0.9
Oil	174,200	2.0
Nuclear	<u>1,195,800</u>	<u>14.0</u>
Total	8,544,239	100.0

The winter peak generally amounts to about 78 percent of the peak recorded during the summer season. As result, most of the scheduled maintenance is performed over the winter months. Table 7.1 shows that after the planned scheduled maintenance and the historic value for forced outages are accounted for, there would be an actual reserve of 21.6 percent. The projected scheduled maintenance is considerably higher than the average for the three previous year as shown on Table 7.2.

The Southern Company Region appears to be in good condition for the Winter 1980-81 season. In addition to its internal needs, there is an opportunity to provide relief to contiguous regions in accordance with Figure 7.1.

Tennessee Valley Authority (TVA) Region

TVA is the largest system in the SERC area, serving municipalities and cooperatives with service areas in seven states. TVA has many multi-purpose hydroelectric projects which produce 15.7 percent of TVA's total energy requirements. Table 7C.1 shows the complete summary of generation by fuels.

TABLE 7C.1
TENNESSEE VALLEY AUTHORITY REGION
PROJECTED GENERATION BY FUELS FOR JANUARY 1981

<u>Type Fuel</u>	<u>Generation (Mwh)</u>	<u>Percent of Total</u>
Hydro	1,816,800	15.7
Coal	7,291,200	62.8
Gas	0	0
Oil	0	0
Nuclear	<u>2,492,400</u>	<u>21.4</u>
Total	11,600,400	100.0

As indicated on Table 7C.1, TVA does not anticipate any generation by gas or oil units. A small amount of oil is used for ignition and flame stabilization in coal-fired units. The energy generated by four nuclear units with a capability of 4,349 Mw, represents a capacity factor of 77 percent.

Although TVA is considered a winter peaking region, the peak has not increased over the last four years. In fact, as Figure 7C.1 shows, the winter peak has decreased. The difference between the 1980 summer peak and the projected 1980-81 winter peak is 3½ percent.

FIGURE 7C.1

Tennessee Valley Authority Region
Summer/Winter Peaks - Summer 1977 Through Winter 1980-81

The projected peak for the winter 1980-81 shown on Table 7.1 was adjusted by TVA from previous forecasts for this period to show a more realistic growth of one percent over the winter 1979-80.

From a load/supply standpoint, TVA appears to be in good condition for the winter 1980-81 season. Table 7.1 indicates an actual reserve of 18.3 percent after all adjustments to capability have been made. The high forced outage rate comes from historic data. The Cumberland No. 2 coal unit, 1275 Mw, will not be available this winter due to a forced outage. Replacement energy will probably come from other coal units since the nuclear units, as previously noted, are now scheduled for about a 77 percent plant factor. Approximately 65 percent of the available reserves shown consists of gas turbines burning No. 2 fuel oil.

Virginia-Carolinas Group (VACAR) Region

On the basis of energy requirements and peak demand, VACAR is the largest of the four electric regions making up the Southeastern Electric Reliability Council. The projected generation by fuel to meet these requirements is shown in Table 7D.1.

TABLE 7D.1
VIRGINIA-CAROLINAS GROUP REGION
PROJECTED GENERATION BY FUELS FOR JANUARY 1981

<u>Type Fuel</u>	<u>Generation (Mwh)</u>	<u>Percent of Total</u>
Hydro	731,407	5.0
Coal	8,630,949	58.7
Gas	0	0
Oil	1,212,000	8.2
Nuclear	<u>4,138,600</u>	<u>28.1</u>
Total	14,712,956	100.0

Nuclear energy plays a large role in reducing the use of oil in the VACAR region. Table 7D.2 shows a comparison between the actual winter 1979-80 fuel use and the projected winter 1980-81 projected fuel use. The 1980-81 projections indicate an oil reduction of about 2,826 barrels/day and an anticipated discontinuance of natural gas as a boiler fuel.

TABLE 7D.2
VIRGINIA-CAROLINAS GROUP REGION
FUEL USE PROJECTED FOR JANUARY 1981 VERSUS ACTUAL FOR JANUARY 1980

<u>Fuel Type</u>	<u>January 1981 Projection</u>	<u>January 1980 Actual</u>	<u>Percent Change Jan. '81 vs. Jan. '80</u>
Gas (Mcf)	0	116,764	(100.0)
Oil (Bbls.)	2,221,623	2,309,221	(3.8)

The demand and supply situation summary for the VACAR region, as shown on Table 7.1, shows an actual reserve of 4.4 percent. Consistent with the other regions, the three year historic forced outages rate was used in developing this summary. Table 7D.3 shows the forced outage rates for the winter 1979-80 and summer 1980 peak months.

TABLE 7D.3
 VIRGINIA-CAROLINAS GROUP REGION
FORCED OUTAGE RATES WINTER 1979-80 AND SUMMER 1980

<u>Utility</u>	<u>Winter 1979-80</u> <u>February</u>	<u>Summer 1980</u> <u>August</u>
Carolina Power & Light Co.	956	855
Duke Power Co.	550	1,072
So. Car. Elec. & Gas Co.	150	327
So. Car. Public Ser. Auth.	0	0
Virginia Electric & Power Co.	<u>2,643</u>	<u>1,537</u>
Total	4,299	3,791

Table 7.1 shows scheduled maintenance considerably higher than that shown in Table 7.2, the historic outage at time of peak. This is due in part to the inclusion under scheduled maintenance of some units being re-converted from oil to coal and the replacement of a steam generator in a nuclear unit.

The demand and supply situation appears to be relatively secure. External transfer capability, as shown on Figure 7.1, amounts to a maximum of 4,750 Mw of unused capacity excluding any limitations that may exist.

8. SOUTHWEST POWER POOL (SWPP or SPP)

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). See Appendix B for list of utilities included in this report.

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.

Table 8.1 shows planned reserve for the entire SPP of 73.2 percent for the 1980-81 winter peak. Net exports of 214 MW bring this figure down to 72.5 percent. Reserve margin after maintenance is 53.1 percent and after inoperable capability is 51.3 percent. When three year historical forced outages are included in the reserve calculation, actual reserve become 33.6 percent.

There appears to be no problem supplying load in the SPP area this winter; however, some problems may exist on an Electric Region basis.

All of the Electric Regions within the Southwest Power Pool (SPP) are summer peaking. The ratio of projected 1980-81 winter peak to actual 1980 summer peak for Regions 8, 10, 21, and 22 are .63, .66, .70, and .73, respectively.

It would appear that with this diversity in seasonal peak load reserve capacity would be adequate. However, utilities use this period to schedule preventive maintenance on their equipment, and utilities that rely heavily upon natural gas as a boiler fuel may have their supply curtailed due to shortages of natural gas during the winter.

Historically, over a three-year winter peak period, Region 8 (Middle South Utilities Group) has had an average maintenance outage of 7.9 percent of planned capability and forced outage (including inoperable capability) of 13.1 percent. However, the Region is projecting maintenance outages totalling 19.3 percent for the 1980-81 winter peak period. This reduces total reserves from 83.6 percent to 49.9 percent (See Table 8.1). Historical average forced outages if they recur would reduce reserve to 27.1 percent. Capacity reserves would appear to be adequate in the Middle South Utilities Group.

Although Region 8 is heavily dependent upon natural gas for generation (57.9 percent in 1979) the utilities are not predicting any major problem in obtaining gas this winter. Utility submission of ERA Form 160 shows that 51.6 percent of Region 8 generation for August 1980 came from gas and they expect 47.3 percent of January 1981 generation to come from gas. Approximately 2,300 MW of this Region's planned capability is oil-fired. Therefore, unavailability of this capacity due to oil shortage would cause the actual reserve to fall below zero. However, it is unlikely that all of the 13.1 percent forced outages assumed in this study would be non oil-fired generation. Therefore, actual reserve should be above zero and no reliability problem should exist in Region 8 even assuming severe contingencies.

The Gulf States Group (Region 10) has had very high percentages of maintenance and forced outages at the time of the winter peaks. These have been 13.6 percent and 18.1 percent, respectively. The high forced outages, which here include inoperable capability, result partly from the curtailment of gas supplies during the home heating season. Table 8.1, which includes the utility projection of 20.6 percent maintenance outages and the historical 18.1 percent for forced outages, show a negative 2.6 percent actual reserve margin. The Region could very well experience severe reliability problems during the 1980-81 winter peak period if historical outages do occur again. In addition, if an oil cut-off occurred and the Big Cajun No. 2 unit No. 1 (540 MW coal-fired) were delayed from its December 1980 in-service date to beyond the winter peak period then possibly an additional 2,500 MW of capacity would be unavailable. This would leave the Gulf States Region in a disastrous state because outside help from the Middle South Area would likely be non-existent due to supply shortages in that area.

The Missouri-Kansas Group (Region 21) has a projected actual reserve margin of 43.5 percent. This includes the effects of 14.8 percent of historical forced outages. Utilities scheduled maintenance projections of 0.7 percent are well below the historical average of 10.5 percent. If the full historical average for maintenance outages were included in the calculations then an additional 1,327 MW of capacity would be unavailable resulting in an actual reserve margin of 26.3 percent. Thus, since the region is not dependent on oil and any reduction in natural gas supplies is already accounted for, there would appear to be no reliability problem in Region 21 for the 1980-81 winter period.

The Oklahoma Group (Region 22) projects a 53.0 percent actual reserve margin this winter. This is in part due to a very low amount of unavailable capacity due to forced outages and fuel related problems during the past three winters, averaging 3.7 percent. Historically the Region has had a three year maintenance outage rate of 11.6 percent, and projects 8.4 percent for this winter. The area, while not dependent upon oil, is heavily dependent on natural gas at the present time for generation. In 1979, 72.7 percent of the generation in Region 22 came from gas. Form 160 data shows that the area is projecting 51.9 percent of its generation to be supplied from gas in January 1981; actual August 1980 use was 65.2 percent. This could be due to winter gas supply reductions but most likely shows the effects of 965 MW of additional coal-fired generation either in-service now or projected by the winter peak period. Thus Region 22 should have an adequate supply of power for the 1980-81 winter period.

TABLE 8.1

SOUTHWEST POWER POOL (SPP)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

<u>MW OR PERCENT</u>	<u>MIDDLE SOUTH UTILITIES GROUP</u>	<u>GULF STATES GROUP</u>	<u>MISSOURI KANSAS GROUP (MOKAN)</u>	<u>OKLAHOMA GROUP</u>	<u>TOTAL SPP REGION</u>
1. PLANNED CAPABILITY	14099	8624	13505	19043	55271
2. PEAK DEMAND	8106	6029	7735	10048	31918
3. PLANNED RESERVES (1-2)	5993	2595	5770	8995	23353
4. PLANNED RESERVES (%) (3/2)x100	73.9	43.0	74.6	89.5	73.2
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	780	589	-220	-1363	-214
6. TOTAL CAPABILITY (1+5)	14879	9213	13285	17680	55057
7. TOTAL RESERVES (6-2)	6773	3184	5550	7632	23139
8. TOTAL RESERVES (%) (7/2)x100	83.6	52.8	71.8	76.0	72.5
9. SCHEDULED MAINTENANCE	2727	1779	96	1604	6206
10. CAPABILITY AFTER MAINTENANCE (6-9)	12152	7434	13189	16076	48851
11. RESERVES AFTER MAINTENANCE (10-2)	4046	1405	5454	6028	16933
12. RESERVES AFTER MAINTENANCE (%) (11/2)x100	49.9	23.3	70.5	60.0	53.1
13. INOPERABLE CAPABILITY ^{1/}	0	0	98	458	556
14. AVAILABLE CAPABILITY (10-13)	12152	7434	13091	15618	48295
15. AVAILABLE RESERVES (14-2)	4046	1405	5356	5570	16377
16. AVAILABLE RESERVES (%) (15/2)x100	49.9	23.3	69.2	55.4	51.3
17. FORCED OUTAGES ^{2/}	1846	1560	1995	246	5647
18. ACTUAL CAPABILITY AFTER FORCED OUTAGES (14-17)	10306	5874	11096	15372	42648
19. ACTUAL RESERVES (18-2)	2200	-155	3361	5324	10730
20. ACTUAL RESERVES (%) (19/2)x100	27.1	-2.6	43.5	53.0	33.6

^{1/} INOPERABLE CAPABILITY IS THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE.

^{2/} FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL THREE YEAR AVERAGE AT THE TIME OF THE WINTER PEAK BEGINNING WITH THE 1977-78 WINTER.

9. WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)

The Western Systems Coordinating Council (WSCC) area includes systems in the Canadian Provinces of British Columbia and Alberta, the States of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and Wyoming, most of the States of Montana and New Mexico, and small sections of the States of South Dakota and Texas. Canadian systems are not included in this report. WSCC is the largest, geographically, of the nine regional councils of the National Electric Reliability Council (NERC). The WSCC region consists of five subregional groups. They are:

- I Northern Power Pool Area
- II Rocky Mountain Power Area
- III Arizona-New Mexico Power Area
- IV Northern California-Nevada Power Area
- V Southern California-Nevada Power Area

For the WSCC region the estimated planned reserve shown in Table 9.1 for the winter peak period is 35.2 percent. In the various subregions, the estimated reserves range from a low of 15.5 percent in the Northern California-Nevada Power Area to a high of 93.1 percent in the Arizona-New Mexico Power Area. Also indicated in Table 9.1 is the estimated effect of forced outages. The actual reserves could range from a low of 8.7 percent to a high of 46.9 percent for the five Electric Regions. Actual reserve for the Council area could be 21.9 percent.

Fuel supplies for the WSCC region are projected to be adequate for the winter months. However, transmission limitations and the circulating clockwise power flow throughout the WSCC interconnected system will adversely affect the ability to transfer coal-fired generation for oil displacement.

In the winter-peaking Pacific Northwest the reservoir storage for the coordinated system was essentially full by September 1, 1980. Assuming median water conditions, the area's generation will be sufficient to meet all firm loads during the winter season.

In Northern California, Pacific Gas and Electric Company's Diablo Canyon No. 1 nuclear unit (1084 MW), previously scheduled for service in February 1981, is now estimated to be in service in May 1981. This date is dependent on the Nuclear Regulatory Commission granting an operating license by December 1980.

Table 9.1

WESTERN SYSTEMS COORDINATING COUNCIL (WSCC) 2

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR WINTER 1980-81 PEAK PERIOD

MW OR PERCENT -----	ROCKY MOUNTAIN POWER AREA -----	NORTHWEST POWER POOL AREA -----	ARIZONA- NEW MEXICO POWER AREA -----	SOUTHERN CALIFORNIA -NEVADA POWER AREA -----	NORTHERN CALIFORNIA -NEVADA POWER AREA -----	TOTAL WSCC REGION -----
1. PLANNED CAPABILITY	6929	42639	13348	23074	14911	100901
2. PEAK DEMAND	5148	33245	6914	16394	12906	74607
3. PLANNED RESERVES (1-2)	1781	9394	6434	6680	2005	26294
4. PLANNED RESERVES (%) (3/2)X100	34.6	28.3	93.1	40.7	15.5	35.2
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-370	-435	-708	3724	2005	4216
6. TOTAL CAPABILITY (1+5)	6559	42204	12640	26798	16916	105117
7. TOTAL RESERVES (6-2)	1411	8959	5726	10404	4010	30510
8. TOTAL RESERVES (%) (7/2)X100	27.4	26.9	82.8	63.5	31.1	40.9
9. SCHEDULED MAINTENANCE	88	1738	1516	2731	892	6965
10. CAPABILITY AFTER MAINTENANCE	6471	40466	11124	24067	16024	98152
11. RESERVES AFTER MAINTENANCE (10-2)	1323	7221	4210	7673	3118	23545
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	25.7	21.7	60.9	46.8	24.2	31.6
13. INOPERABLE CAPABILITY 1	170	951	229	469	829	2648
14. AVAILABLE CAPABILITY (10-13)	6301	39515	10895	23598	15195	95504
15. AVAILABLE RESERVES (14-2)	153	6270	3981	7204	2289	20897
16. AVAILABLE RESERVES (%) (15/2)X100	22.4	18.9	57.6	43.9	17.7	28.0
17. FORCED OUTAGES 3	111	976	741	1575	1160	4563
18. ACTUAL CAPABILITY AFTER FORCED OUTAGES (14-17)	6190	38539	10154	22023	14035	90941
19. ACTUAL RESERVES (18-2)	1042	5294	3240	5629	1129	16334
20. ACTUAL RESERVES (%) (19/2)X100	20.2	15.9	46.9	34.3	8.7	21.9

1 INOPERABLE CAPABILITY IS THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE.

2 CANADIAN SYSTEMS ARE EXCLUDED.

3 FORCED OUTAGES ESTIMATES ARE A THREE YEAR HISTORICAL AVERAGE USING DATA FROM THE WSCC REPORT -SUMMARY OF LOADS AND RESOURCES. FOR THE NORTHWEST POWER POOL AREA, THE FORCED OUTAGE WAS ESTIMATED USING DATA FROM THE FPC FORM 12E-2.

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

Electric Regions in the United States

June 1, 1980 *

Appendix 1

P. 2 of 2

* First revision of July 1, 1979 map.

Reliability Council

- ECAR -East Central Area Reliability Coordination Agreement
- ERCOT -Electric Reliability Council of Texas
- MAAC -Mid-Atlantic Area Council
- MAIN -Mid-America Inter-pool 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

Electric Region

ECAR

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)

5

MAAC

Pennsylvania-New Jersey-Maryland Interconnection (PJM)

6

MAIN

Commonwealth Edison Co. Illinois-Missouri Group (ILLMO) Wisconsin-Upper Michigan Systems Group (WUMS)

17

19

MARCA

Mid-Continent Area Power Pool (MAPP)

20

NPCC

New England Power Pool (NEPOOL) New York Power Pool (NYPP)

3

4

23

DT

Texas Interconnected Systems Group (TIS)

SERC

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SWPP

WSCC

Florida Coordinating Group (FCG) Southern Company Group Tennessee Valley Authority Group (TVA) Virginia-Carolinas Group (VACAR)

Middle South Utilities Group Gulf States Group Missouri-Kansas Group (MOKAN) Oklahoma Group

Rocky Mountain Power Pool (RMPP) Northwest Power Pool (NWPP) Except for Idaho-Utah Group Arizona-New Mexico Group Southern California-Nevada Group Northern California-Nevada Group Idaho-Utah Group of the Northwest Power Pool

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