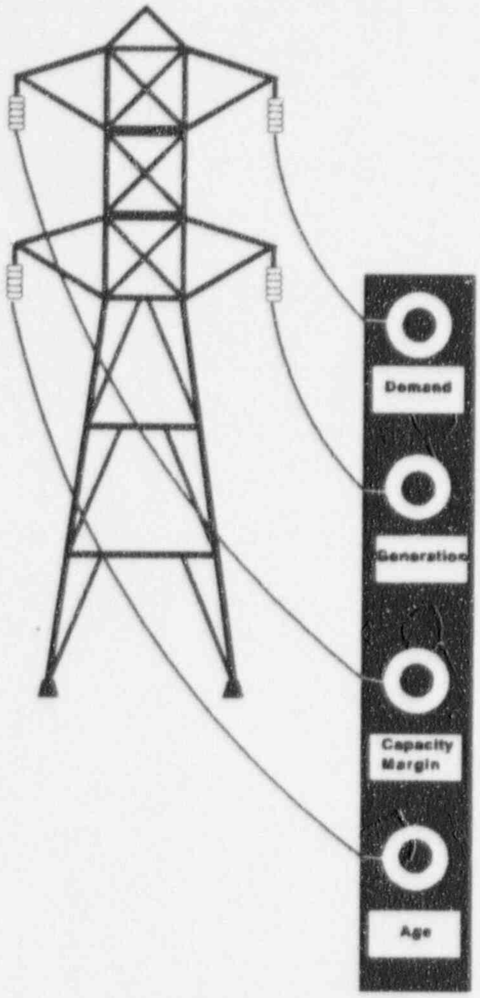

Grid Performance Factors

AEOD C97-01

MARCH 20, 1997

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United States Nuclear Regulatory Commission
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CONTENTS

CONTENTS (cont.)

APPENDICES

TABLES

FIGURES

ABBREVIATIONS

1E	safety-related electrical
ac, AC	alternating current
ANO 1	Arkansas Nuclear One, Unit 1
CFR	Code of Federal Regulations
CT	current transformer
DOE	U. S. Department of Energy
ECAR	East Central Area Coordination Agreement
EDG	emergency diesel generator
EEI	Edison Electric Institute
ERCOT	Electric Reliability Council of Texas
ES&D	Energy Supply and Demand
ESF	engineered safeguards features
FRCC	Florida Reliability Coordinating Council
GIC	geomagnetically-induced currents
GT/IC/JE	gas turbine/internal combustion engine/jet engine
HVDC	high voltage direct current
Hz	Hertz
IE-411	DOE report
IPP	independent power producers
kV	kilovolt
LER	licensee event report
LOOP	loss of offsite power
MAAC	Mid-Atlantic Area Council
MAAC PJM	Pennsylvania, New Jersey, and Maryland subregion of MAAC
MAIN	Mid-America Interconnected Network
MAIN EMO	Eastern Missouri subregion of MAIN
MAIN NIL	Northern Illinois subregion of MAIN
MAIN SCI	South Central Illinois subregion of MAIN
MAIN WUM	Wisconsin, Upper Michigan subregion of MAIN
MAPP	Mid-Continent Area Power Pool
MW	megawatt

MWe	megawatt, electric
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NPCC NE	New England subregion of NPCC
NPCC NY	New York subregion of NPCC
NUDOCS	Nuclear Document System
NUREG	NRC technical report designation
OR	operating reserve
PECO	Philadelphia Electric Company
PT	potential transformer
PURPA	Public Utilities Regulatory Policies Act
SCSS	Sequence Coding and Search System
SERC	Southeastern Electric Reliability Council
SERC FLA	Florida subregion of SERC
SERC SOU	Southern subregion of SERC
SERC TVA	Tennessee Valley Authority subregion of SERC
SERC VAC	Virginia-Carolinas subregion of SERC
SLOD	severe line outage detector
SPP	Southwest Power Pool
SPP NOR	Northern subregion of SPP
SPP SE	Southeastern subregion of SPP
SPP WCN	West Central subregion of SPP
SPS	special protective system
TS	Technical Specifications
USI	unresolved safety issue
WNP 2	Washington Nuclear Plant, Unit 2
WSCC	Western Systems Coordinating Council
WSCC ANM	Arizona-New Mexico subregion of WSCC
WSCC CSN	California-Southern Nevada subregion of WSCC
WSCC RM	Rocky Mountain subregion of WSCC
WSCC NW	Northwest subregion of WSCC

EXECUTIVE SUMMARY

The reliability of offsite power[1] is important to nuclear safety. Accident sequences initiated by the loss of offsite power are important contributors to risk for most nuclear plants[2]. In 1979, the Nuclear Regulatory Commission identified the loss of all AC electrical power to the nuclear plant, called station blackout, as an unresolved safety issue. Station blackout was shown to be an important contributor to the total risk from nuclear power plant accidents. A task action plan A-44 was issued in July 1980. The final report on Unresolved Safety Issue A-44 was contained in NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," June 1988. In NUREG-1032, the grid was assumed to be stable and reliable.

This study was initiated to collect operating experience on grid disturbances which may have impacted nuclear power plant operation and the availability of offsite power for the period of 1985 to the present. In order to communicate the findings of the study, it became necessary to inquire into the nature of the grid and its operation. The grid is defined and some of its basic characteristics are addressed.

An event in 1989 at the Virgil Summer Nuclear Plant caused a severe perturbation of the Eastern Grid which resulted in a loss of offsite power to Virgil Summer. The Los Angeles earthquake of January of 1994 resulted in a severe perturbation of the Western Grid. In December of 1994, the Western Grid experienced another severe perturbation that resulted in the scramming of both Diablo Canyon units.

In 1995, a series of equipment failures at a nearby substation caused the two Limerick units to scram. The resultant perturbation was seen throughout the Eastern Grid.

In 1996, the Western Grid experienced two major disruptions, one on July 2 and the second on August 10. The August 10 event lead to the scramming of both Diablo Canyon units and Palo Verde 1 and 3. Diablo Canyon declared their 500 kV offsite power system inoperable.

Four reports of potential problems related to grid stability were found in which licensees reviewed stability analyses and instabilities were discovered. The reviews were done for a variety of reasons, including as a followup of an information notice, in response to a question raised during an electrical distribution functional inspection, and following actual events.

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1 Offsite power is "electric power from the transmission network to the onsite distribution system ... supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to these systems is acceptable." 10 CFR 50, Appendix A, Criterion 17, "Electric Power Systems"

2 In this study, the term "plant" is used according to usage more common to the NRC. A "plant" is a single generating unit when differentiation between "unit" and "station" has relevance, or the entire station where the differentiation is not relevant. NERC usage of the term is more strict, in that plant usually means all generating units at a generating station.

The condition of the grid is dynamic: capacity changes; demand changes; transmission patterns change; equipment ages; new equipment is brought on line; and equipment is retired. Two relatively new factors are emerging: independent power producers and restructuring of the electric industry.

The North American Electric Reliability Council has adopted programs and procedures to deal with forecasting, normal operations, emergency conditions, and recovery from system collapse. The programs and procedures appear to give a basis for assurance of orderly operation.

The "grid," the bulk power supply, as managed by the North American Electric Reliability Council member utilities, has adequate resources to give reasonable assurance that the reliability of the system will be maintained under normal conditions. On the whoie, the grid is stable and reliable; however, problems described in the Regional assessments as stated in Section 4, as well as uncertainties introduced by restructuring of the electric industry indicate the need to monitor grid conditions on a regular basis.

1.0 INTRODUCTION

Station blackout is the complete loss of alternating current (AC) electrical power in a nuclear power plant. This includes all normal and alternate AC power from offsite sources[1], loss of all onsite AC power produced by the nuclear unit, and loss of all onsite emergency AC power (produced by emergency diesel generators, usually). Because many of the systems which are required for removing reactor core decay heat and containment heat depend upon AC power, the consequences of a station blackout could be severe. Station blackout and other accident sequences involving loss of offsite power are known to be important contributors to the total risk from nuclear power plant accidents. As operating experience accumulated, the concern arose that both the onsite and offsite emergency AC power systems might be less reliable than originally anticipated. The Nuclear Regulatory Commission designated station blackout as an unresolved safety issue (USI); a task action plan (A-44) was issued in July 1980, and work was begun to determine whether additional safety requirements were needed. The final report on USI A-44, NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," was issued in June 1988 [1]. In NUREG-1032, the grid was assumed to be stable and reliable.

This study was initiated to collect operating experience on grid disturbances which may have impacted nuclear power plant operation and the availability of offsite power for the period of 1985 to the present. In order to communicate the findings of the study, it became necessary to inquire into the nature of the grid and its operation. In the following sections, the grid is defined and some of its basic characteristics are addressed. Then operational experiences and potential problems are discussed.

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1 Offsite power is "electric power from the transmission network to the onsite distribution system ... supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to these systems is acceptable." 10 CFR 50, Appendix A, Criterion 17, "Electric Power Systems"

2.0 DATA SOURCES AND SEARCH STRATEGIES

Information used in this study was obtained from the North American Electric Reliability Council (NERC), the individual Reliability Councils, the Department of Energy (DOE), NRC documents, Sequence Coding and Search System (SCSS) searches, the Nuclear Documents System (NUDOCS) searches, 10 CFR 50.72 reports, and reports from a variety of other sources.

SCSS searches were conducted for licensee event reports (LERs) dated from January 1, 1985, to the present for high- or medium-voltage AC system problems related to all scrams. NUDOCS search strategies used key phrases and keywords such as GRID FLUCTUATIONS, GRID PERTURBATIONS, and GRID DISTURBANCES, and DEGRADED near GRID.

Individual Reliability Councils were contacted to obtain a copy of their IE-411, yearly status reports to DOE [2]-[10]. The information on demand, generation, capacity margin, emergency procedures, and regional operating philosophy for assuring the grid function was contained in these documents.

The NERC Energy Supply and Demand (ES&D)® database [11] provided the means to update the data. Additional documents received from NERC include the "NERC Operating Manual," [12] the "1995 Annual Report," [13] "Reliability Assessment 1996-2005," [14] and several other documents.

DOE information included DOE/EIA-0095, "Inventory of Power Plants in the United States 1994," [15] data from a database which contained information on major grid disturbances, and other reports. Mr. Norton Savage of DOE supplied data and provided assistance vital in locating these documents.

3.0 DEFINING THE "GRID"

On November 9, 1965, the northeastern U.S. experienced a power failure which directly affected 30 million people in the U.S. and Canada. [16] On Ju[illegible], 1977, New York City experienced a blackout, following lightning strikes in the Ind[illegible] Point 3 switchyard causing it to scram and lose offsite power. [17] No Federal regulation of the reliability of the bulk power supply was provided by the Federal Power Act of 1935 and none was subsequently approved following either the 1965 or the 1977 incidents. The promotion of the reliability of the bulk power supply is the mission of the North American Electric Reliability Council through its member Reliability Councils. Although the current Reliability Councils can trace their history back further than 1965, these two events had major impacts on the development of their structure, functions, programs, procedures, and operation. These Councils were made up of members representing the electric power utilities which engage in bulk power generation and transmission in the United States, Canada, and parts of Mexico.

Information in this report is generally limited to the 48 contiguous states of the United States. The goal of the reliability councils was to foster reliable operation of the grid through coordinated operation and planning of generation and grid facilities.[2] [12] Table 3.0.1 names the member councils and gives the abbreviation by which each is usually called. Figure 3.0.1 shows the geographic location of the member councils throughout the United States.

Table 3.0.1: Member Councils of the North American Electric Reliability Council [14], [18]

ECAR	East Central Area Reliability Coordination Agreement
FRCC	Florida Reliability Coordinating Council
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
ERCOT	Electric Reliability Council of Texas
WSCC	Western Systems Coordinating Council

Figure 3.0.1: North American Electric Reliability Councils [18]

2 Specific Regional information is sometimes given as representative of all Regions. While it may be representative, there may be differences in Criteria from Region to Region. Information on the same subject for Regions other than the one named should be obtained from the Criteria of that Region.

"Interconnections" (the term the electric power industry uses instead of grid) are a strategy for providing power from the plants via an interconnected transmission network to the entities that resell it to the consumer via a distribution network. The Western Interconnection is composed of one Reliability Council, WSCC. The Eastern Interconnection comprises ECAR, FRCC, MAAC, MAIN, MAPP, NPCC, SERC, and SPP. The Texas Interconnection is also composed of one Reliability Council, ERCOT.

"Continuity of service to load is the primary objective of the minimum Operating Reliability Criteria. Preservation of interconnections during disturbances is a secondary objective except when preservation of the interconnections will minimize the magnitude of load interruption or will expedite restoration of service to load" are the objectives of WSCC. [10] SERC states that their regional criterion is "to assure that ... cascading outages will not result from any foreseeable contingencies." [8] MAAC states that "The bulk electric supply system shall be planned and constructed in such manner that it can be operated so the more probable contingencies can be sustained with no loss of load." [4]

The objectives for each Reliability Council vary but, whether explicitly stated or implied in context, the Reliability Councils' operating philosophy is to prevent cascading failure[3], [19] provide reliable power supplies, and maintain the integrity of the system. Long-term and short-term procedures are in place nationwide to project demand, to provide for reserves to meet peak demand, and to provide for both likely and unlikely contingencies when demand exceeds capacity and other emergencies. These procedures include a load reduction program which calls for manual steps to stabilize the grid and a series of automatic actuations to prevent collapse of the grid. The load reduction procedures for MAAC are shown in Table 3.0.2.

Table 3.0.2: Load Reduction Procedures [4]

1.	Curtailment of nonessential power company station light and power (power plants)
2.	Reduction of controllable interruptible/reducible loads
3.	Voltage reductions (brownouts)
4.	Reduction of nonessential load in power company buildings (other than power plants)
5.	Voluntary customer load reduction
6.	Radio and television load reduction appeal
7.	Manual load shedding (rotating blackouts)
8.	Automatic actuation of underfrequency relays which shed 10 percent of load at 59.3 Hz, an additional 10 percent at 58.9 Hz, and an additional 10 percent at 58.5 Hz

3 The term "cascading failure" refers to the uncontrolled successive loss of system elements in which the loss of each successive element is contingent upon prior losses of elements. In plain words: a power plant trips offline and the nearby plants cannot cope with the additional loads so they trip offline. That places an even larger load on the nearby plants and these plants trip offline etc., until the entire electric grid shuts down.

Generators operate at 60 Hz (cycles per second). If generation is not exactly equal to load, frequency will vary. In fact, minor variations in frequency exist over time and are routinely corrected. Higher-than-expected loads, loss of generation, and faults can produce frequency transients. If the situation warrants, the utility may reduce voltage by up to 5 percent to bring frequency back to 60 Hz. Operating at higher or lower frequencies or voltages can damage generating equipment and damage or cause malfunction of equipment loaded to the grid.

Other procedures allow disconnecting from the grid (islanding) areas which have generating units that are capable of supplying local loads, but that would be tripped if connected to a degrading grid.

When specific facilities frequently experience disturbances which unduly burden other systems, the owners of the facilities are required by their Council to take measures to reduce the frequency of the disturbances, and cooperate with other utilities in taking measures to reduce the effects of such disturbances.

The emergency procedures also provide for the safe shutdown of the system and for the restart. Because many plants cannot be restarted without external power, "blackstart" units are available at various locations as determined by the utility. The blackstart units are capable of starting up without any electricity being supplied to them from the grid, including self-excitation; therefore, they restart and produce power to restart other units. The typical blackstart capability is described as follows: "These [blackstart] units comprise diesel and combustion turbine units, conventional hydro, and pumped storage hydro units. Normal operating procedures for pumped storage hydro plants require maintaining sufficient water in the upper reservoir at all times to provide for system startup power. Satisfactory tests have been conducted to prove the capability of black start of conventional hydro, pumped storage hydro, and some steam and combustion turbine units to provide system startup power." [8]

4.0 GRID CHARACTERISTICS

This section addresses demand, generation, capacity margin, age of power plants, and emergency procedures.

4.1 Demand

Demand[4] is the rate at which electricity is delivered to a customer. Demand varies with the hour of the day, day of the week, month of the year, temperature, humidity, and other factors. When demand is greatest, it is said to "peak." Peak seasonal demand occurs in the summer in all areas except Florida (FRCC) and the Pacific Northwest (WSCC NW), which have winter peaks. [11]

To meet expected demand, utilities establish a baseload capacity[5], the amount of electricity they need to produce continuously, and an operating reserve[6] for responding to increased demand. This operating reserve is called spinning[7] or non-spinning[8] and can be loaded up to its limits in ten minutes. Spinning reserve is already synchronized to the grid, while non-spinning reserve is capable of being started and loaded within ten minutes. Some areas also have a thirty minute reserve requirement. Nuclear plants are generally base load units as are most steam plants.

Peak demand is expected peaks estimated by combining such factors as previous use, the number of new customers, weather forecasts, and other information into a demand forecast. Demand forecasting is not done on a worst case scenario. It does not anticipate the demand during unusually severe weather or other unforeseeable factors which may affect demand.

> An example of severe weather effects on demand (and capacity) occurred on January 18, 1994, in Midwest and Mid-Atlantic areas of the United States. Only MAAC and Virginia Power had to institute the manual curtailment of firm load (rotating blackouts), but less drastic procedures were instituted throughout most of the Eastern Interconnection.

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4 Demand is the rate at which electric energy is delivered to or by a system or part of a system, ... at a given instant or averaged over any designated interval of time. [19]

5 Baseload capacity is used to serve an essentially constant level of customer demand. [19]

6 Operating reserve is that capability above firm system demand required to provide for regulation, load forecasting error, equipment error, forced and scheduled outages, and local area protection. [19]

7 Spinning reserve is unloaded generation, which is synchronized and ready to serve additional demand... [19]

8 Nonspinning reserve is that operating reserve not connected to the system but capable of serving demand within a specific time, or interruptible demand that can be removed from the system in a specified time. Interruptible demand may be included in the nonspinning reserve provided it can be removed from service within ten minutes. [19]

The temperature as measured at the Washington National Airport began to drop from about 35°F. at 5 a.m. to 8°F. at midnight. [20] In the MAAC PJM [21] area and in Northern Virginia, [22] peak electric demand in the afternoon and evening increased inversely with the temperature when it was expected to drop with the change in usage from commercial to residential. Because the temperature decreased to atypical values, the increase in residential loads exceeded the decrease in commercial loads. Demand peaked at 7:00 p.m. and remained higher than the daytime peaks through midnight of the following day. Figure 4.1.1 shows the relationship of temperature to peak demand for the 24 hours beginning at 0000 hours on January 18.

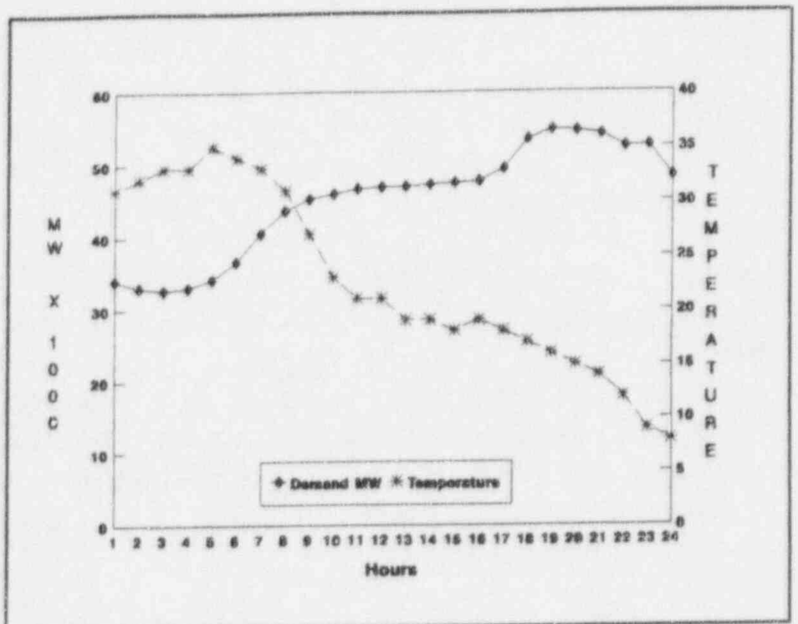

Figure 4.1.1: Temperature vs. Peak Demand on January 18, 1994 [20], [21], [22]

Utilities throughout the Eastern Interconnection began emergency procedures to reduce demand. Emergencies were declared in Pennsylvania, Maryland, and the District of Columbia. Government offices and many businesses closed early on January 19 and remained closed on January 20. The emergency was ended by midday on January 20, though some voltage reductions continued into the evening.

When demand is projected to exceed supply as it did in the January 18, 1994, cold spell, utilities purchase power from adjacent systems. In this case, these systems were also strained by the same cold weather problems; but the New York Power Pool did reduce voltage to its customers and imported power from the New England Power Pool and Canada in order to assist the PJM area. SERC FLA, through SERC SOU also exported power to the mid-Atlantic States. [23]

Because of the cooperation of all entities involved, the load reduction procedures were successful and the Eastern Interconnection was never close to loss of load or collapse because of low frequency.

Demand for electricity by nuclear plants usually occurs when the unit is not producing enough power to supply house loads which may include the safety-related systems. Some nuclear plants supply safety-related loads directly from offsite power at all times. This

power must be available at all times. Power to start up must also be supplied to the nuclear unit's generator. Offsite power for nuclear plants is not included in the utility's demand management program, but it may be affected by an automatic actuation in response to a grid fault. That is, a nuclear plant's voltage will not be reduced, nor will the plant load be shed by the demand management schemes; however, grid faults have caused nuclear plants to be isolated from the grid. See Section 5 for examples.

All Reliability Councils project a yearly increase in peak demand over the next ten years. ECAR projects a 1.85 percent increase in peak demand, ERCOT estimates a 2.0 percent increase, MAAC's forecasted increase is 1.4 percent, MAIN expects to see a 1.75 percent increase, MAPP projects a 1.9 increase in peak demand, NPCC expects the lowest increase - 1.0 percent, SERC estimates a 2.1 percent increase, SPP anticipates a 1.6 percent increase in peak load, and WSCC is forecasting a 1.2 percent increase in peak demand for WSCC NW, 1.7 percent for WSCC RM, a 1.9 percent increase for WSCC ANM, and a 1.4 percent increase in WSCC CSN. [14]

See Appendix A for charts showing peak demand projections for each area.

4.2 Generation[9]

A utility generates electricity by various means: steam turbines, gas turbines, internal combustion engines, jet engines, hydro turbines, and a number of other means. Additional electricity may be furnished by independent power producers.

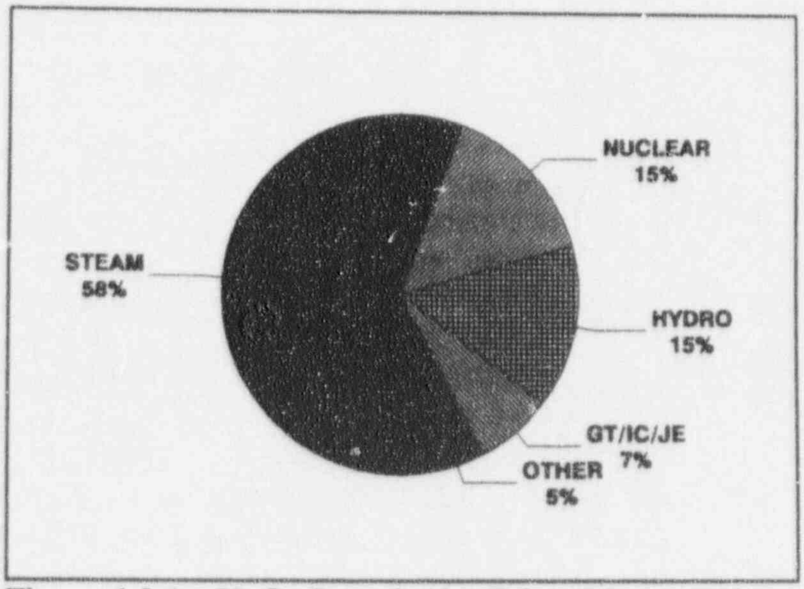

Figure 4.2.1: U. S. Capacity by Prime Mover [11]

Appendix A contains charts of rated capacity[10] vs actual generation for 1994 by region and subregion developed from information found in the NERC ES&D® database showing percentage of the total capacity which is generated by each type

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9 Generation is defined as the process of producing electrical energy from other forms of energy; also, the amount of electricity produced. It is also used to indicate the equipment for producing electricity, especially when the term generating capacity is used. [19]

10 Capacity is defined as the rated continuous load carrying ability ... of generation ...equipment. [19]

of prime mover. Also, the nuclear units which contribute to the capacity in the region or subregion are named. Steam turbines[11], however fired, are the principle means of electric generation in all but two subregions, where nuclear steam electric plants provide 51 percent of the power generated and hydro/pumped storage units provide 68 percent of the power generated. There are no nuclear units in two sub-regions. [11]

By generator nameplate rating, nuclear units range from 75 MW to 1403.2 MW, and average about 908.6 MW. Steam turbines[11] range from 3 MW to 1425.6 MW, however, the average steam unit generates 202 MW. Gas turbines range from 2.5 MW to 138.1 MW and average 38 MW. Internal combustion engines range from less than 1 MW to 21.4 MW, and average 2 MW. Hydro units range from less than 1 MW to 700 MW, and average 27.7 MW. Pumped storage plants are tallied with hydro units. Steam units produce 58 percent of the generation nationally; gas turbines/internal combustion engines/jet engines (GT/IC/JE), 7 percent; nuclear, 15 percent; and hydro, 15 percent. Figure 4.2.2 compares the total number of power plants by types to the amount of generation produced by that type and Figure 4.2.3 depicts the average size of the different type of power plants.

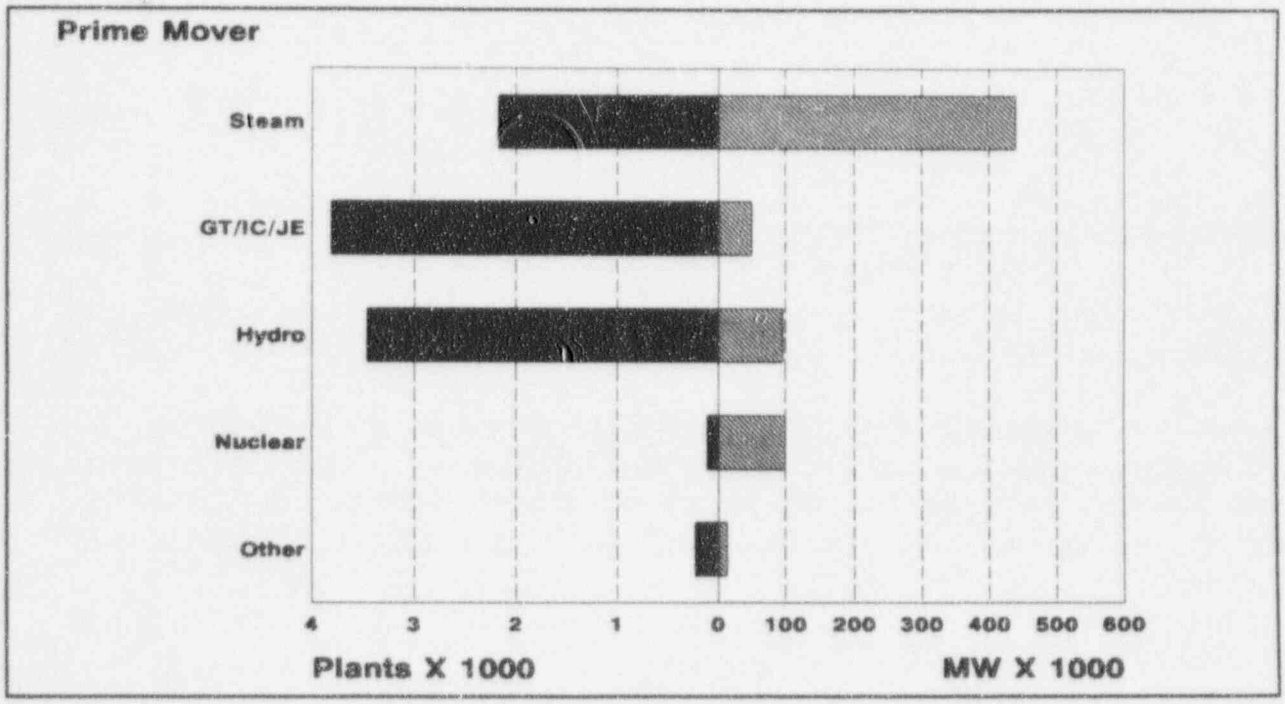

Figure 4.2.2: Total Number of Plants vs Total Capacity of Plants by Prime Mover [11]

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11 Nuclear units are steam electric plants but are tallied separately in this study as they are in the Reliability Councils' IE-411 responses and most other literature.

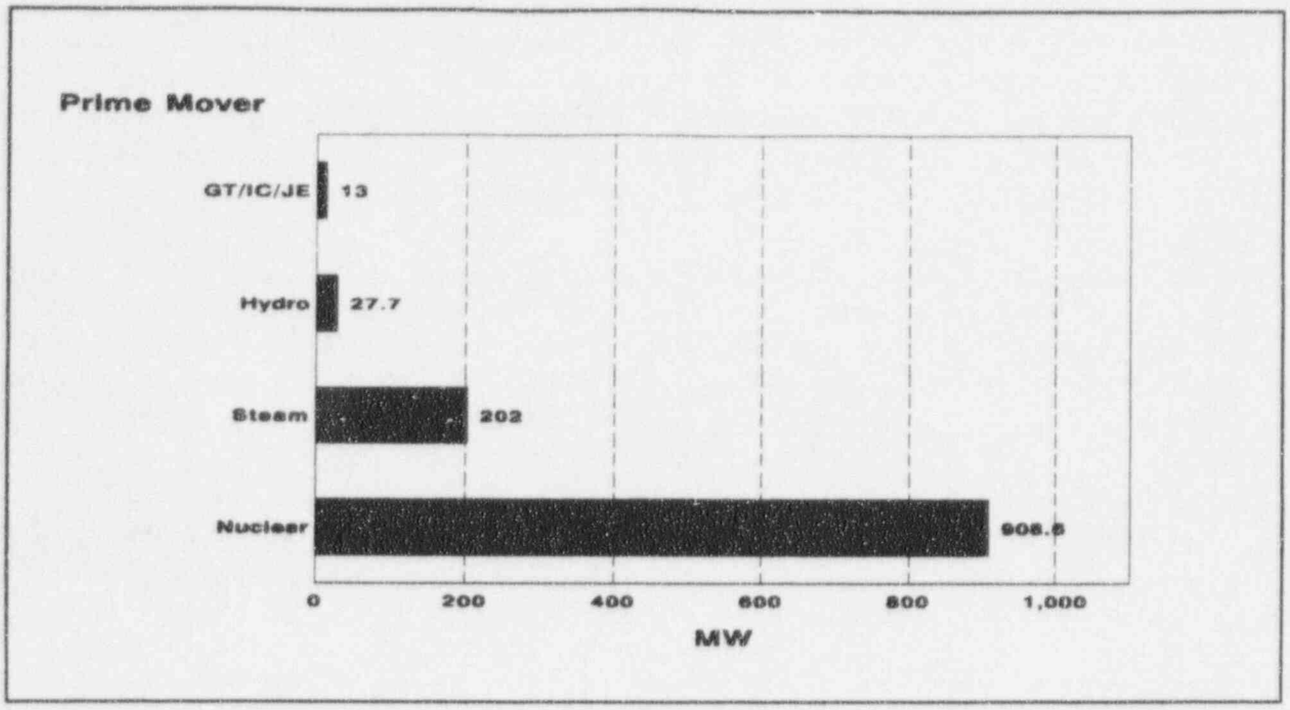

Figure 4.2.3: Average Generating Capacity of Power Plants by Prime Mover [15]

4.3 Capacity Margin [13]

This section addresses capacity margin.[12] Capacity margin is the amount by which generating capacity exceeds the forecast peak demand. [19]

Events have shown that factors such as unit availability and transmission line capacity affect the adequacy of capacity margin that is actually available for use. Improving unit availability and improving transmission line reliability are the principal methods specified by the Councils for maintaining adequate capacity margin. Bringing units under construction on

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[12] Capacity margin (%) = {net capacity resources (maximum output of its generators
+ the maximum output of the generators of the independent power producers in the area
+ power purchases
- the capacity of inoperable generators
- power to run the power plants
- sales)}
MINUS
{net internal demand
- direct control load management
- interruptible demand, if they can be made available to the system in ten minutes or less}
DIVIDED BY
{net capacity resources}
EXPRESSED AS A PERCENT. [11]

line and purchasing power from non-utility generators were also mentioned as means of improving the capacity margin status.

The charts in Appendix A, which were developed from data given in the ES&D® database, show capacity margin projections for 1996 to 2005, as well as demand projections for that period. The term "projection" is particularly fitting to describe capacity margins in that the numbers get less firm as the distance from the present increases.

The adequacy[13] of the projected capacity margin is determined by each Council by comparing the percent of projected capacity margin to an acceptable percent or by probabilistic assessment. ECAR uses the probabilistic method and has determined that annual generation availability must remain above 78 percent for the dependence on supplemental capacity resources[14] to remain at less than one to ten days per year. Their average annual generation availability for the past ten years has averaged 80.1 percent and was 81.7 percent for 1995. For ECAR, generation availability is critical. The aging of generating capacity necessitates increased maintenance and lengthened outages. By 2005, 59 percent of ECAR's capacity will be over 30 years old and about 22 percent will be over 40 years old. [15]

ERCOT capacity additions have been utility owned, but this year, ERCOT is projecting a higher percentage of IPP capacity additions, which are unidentified and uncommitted at present. ERCOT's minimum capacity margin criteria is 13 percent. Their projected margins - from 18.3 percent to 10.8 percent - are considered adequate if load serving entities allow sufficient lead time to get capacity additions on line. [14] MAAC projects adequate capacity to meet Regional reliability goals of 20 percent reserve margin if undetermined resources can be committed within the lead time available. [14] MAIN uses the loss of load probability analysis to assess the adequacy of their system. MAIN will have adequate generating capacity to meet its one-day-in-ten-year criterion throughout the entire period. [14] MAPP requires a 15 percent minimum planning reserve margin[15] above non-coincident demand[16]. They do not expect to meet that goal based on proposed and committed additional generation capacity; however, power sources are judged adequate over the ten-year period. [14]

NPCC states that near-term availability of operable capacity in New England may be lower than required to meet customer demand because the three Millstone Nuclear Units, the Connecticut Yankee Nuclear Unit (Haddam Neck), and the Maine Yankee Nuclear Unit are

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13 Adequacy is defined as the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. [19]

14 Supplemental capacity resources include assistance from neighboring Regions, contractually interruptible demands, and direct control load management. [19]

15 Planning reserve margin is the difference between ... expected annual peak capability and expected annual peak demand expressed as a percentage of the annual peak demand. [19]

16 Non-coincident demand is the sum of two or more demands that occur in different demand intervals. [19]

shut down. On the long term, compensation for the lack of output from the named nuclear units in the form of increased dependence on IPPs, increased import of power from Canada, and other potential sources will provide adequate resources for the period. The New York area anticipates adequate reserve margin over the period. For NPCC, IPPs have become the second largest source of electricity behind nuclear [14]

SERC lists their capacity resource margin as 15 percent throughout the period, which is considered adequate. [14] Note that Florida is included in this projection. The capacity margins of SPP range from 16.4 percent to 13 percent. SPP expresses concerns that generation reliability is difficult to assess in the increasingly competitive marketplace. They report that operators had difficulty accessing resources (without regard as to price) on several days in 1995. [14]

WSCC reports each sub-region separately, listing four issues which could impact reliability to varying degrees: 1) unusual operating conditions and potential voltage instabilities, 2) competition and increasing pressure to reduce costs, 3) changes in the structure of the electric industry, and 4) uncertainties associated with competition and change. WSCC NW reports very high water levels resulting in surplus power sales. They also report steps taken to alleviate the potential for voltage collapse during peak demand conditions. WSCC RM reports more than adequate capacity to meet peak demand requirements. WSCC ANM reports that competition and deregulation has begun to affect operations and expansion plans. They express concern that some aspects of deregulation adds uncertainties to the planning process and could adversely affect reliability. Environmental concerns have also impacted operations. WSCC CSN reports significant changes in the electric power industry within California will occur as a result of regulatory action by the California Public Utilities Commission in their December 20, 1995 decision on restructuring the electric power industry (q.v.). On the whole, WSCC assesses its capacity margins adequate for the projected period. [14]

4.4 Plant Age

The information concerning age of power plants was developed from "Inventory of Power Plants in the United States 1994." [15] The information concerning the age of power plants in Table 20 is titled "Year of Initial Operation." The power plant being operated at a site could be as old as the initial startup date would indicate, parts of it may be original equipment, everything may have been replaced many times since startup, or the original plant may have been razed and a new plant built on the site. Almost all of the oldest plants are hydro units and some of them are known to be in excess of 60 years of age. This section's charts and tables equates age with initial startup date - maximum possible age.

The power plant with the oldest initial operational date in the United States is an 900 KW hydro unit located in California. Other plant sites with an initial operation before 1900 are located in New York, North Carolina, Texas, Utah, Vermont, and Washington.

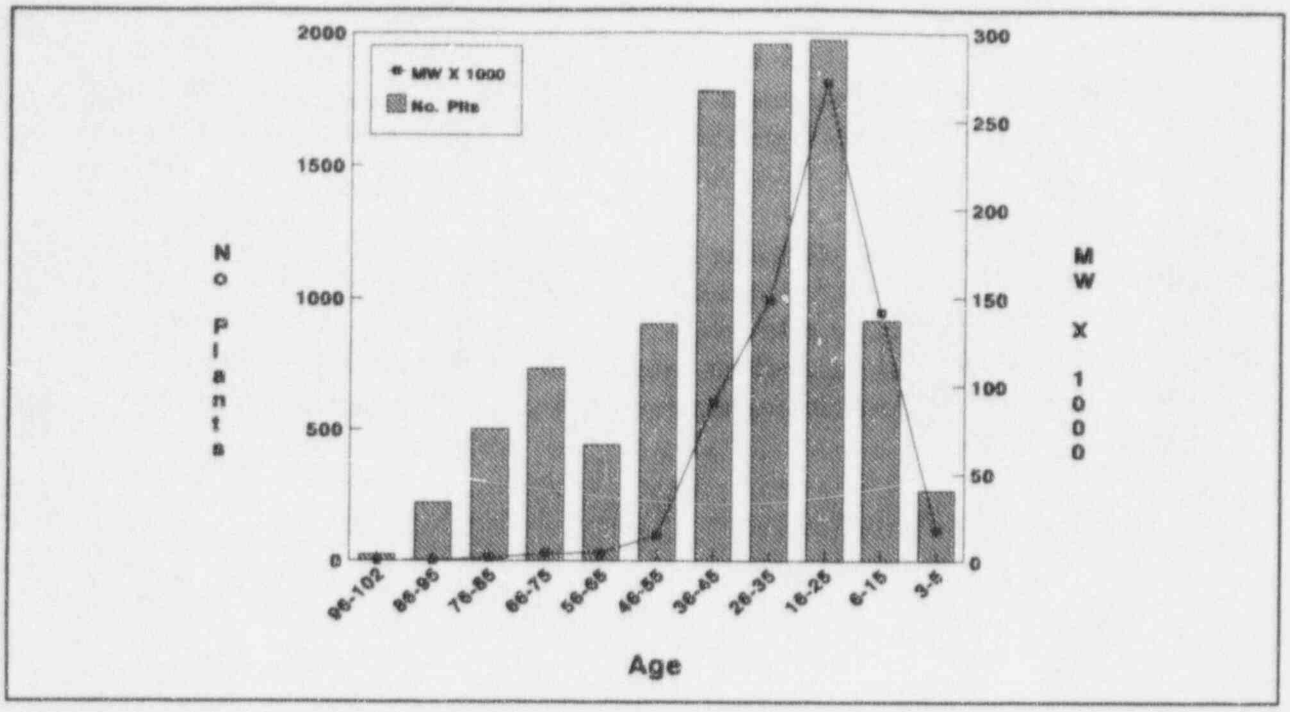

Figure 4.4.1: Plant Age [15]

Figure 4.4.1 shows the number of plants built in each decade and their average capacity. Note that both peaked in the 1970s.

Table 4.4.1: Number and Capacity Power Plants in the United States by Age [15]

Age	Period	No.	Pct.	MW	Pct.
96-105	1890-1899	23	0.2	14.9	0.0
86-95	1900-1909	221	2.3	426.1	0.1
76-85	1910-1919	503	5.2	1908.4	0.3
66-75	1920-1929	732	7.5	4320.8	0.6
56-65	1930-1939	441	4.5	4703.6	0.7
46-55	1940-1949	902	9.3	14977.6	2.1
36-45	1950-1959	1780	18.3	90592.0	13.0
26-35	1960-1969	1958	20.2	149033.7	21.4
16-25	1970-1979	1972	20.3	271513.7	39
6-15	1980-1989	914	9.4	141854.2	20.4
2-5	1990-1993	269	2.8	17501.6	2.5

Although 47.3 percent of the operating plants may be older than 35 years, they produce only about 16.8 percent of the total U.S. electrical capacity. An additional 60.4 percent of U.S. electrical capacity is produced by plants which may be 16 to 35 years old. The newest plants - 2 to 15 years old - produce 22.9 percent of the power with 12.2 percent of the plants. See Table 4.4.1.

With 38.2 percent of the U.S. electricity generated by plants 26 years or older, age has the potential to become a factor in grid stability. As ECAR expressed, the need for equipment outages may increase as well as their length. [14] The event at Virgil Summer in 1989 listed the age of nearby plants and the need for extra protection for them as a factor in the event. Appendix B contains additional information on plant age, sorted alphabetically, by maximum age, and by average age.

4.5 Emergency[17] Procedures

Although regional Reliability Council procedures differ, the thrust is the same: maintain the reserve margin to supply excess demand; but, when reserves drop, take steps to protect the integrity of the grid. The steps detailed in this section are taken from one Reliability Council report as representative of steps taken to achieve these goals. In capital letters, the responsibility for restoring operating reserves is spelled out: "IN THE EVENT OF OPERATING RESERVE DEFICIENCY, THE DEFICIENT SYSTEMS HAVE THE PRIMARY RESPONSIBILITY FOR RESTORING OPERATING RESERVES TO THE DESIRED LEVEL. When the deficient systems are unable to correct the deficiency, all systems in [region] should take actions to aid in restoring Operating Reserve." [5]

I. Operating Reserve (OR) Deficiency Condition

- A. The [Region] Coordination Center shall
  1. monitor the OR status,
  2. analyze daily reports,and
  3. conduct load and capacity surveys.
- B. If OR is below minimum,
  1. declare a [region] Operating Reserve Deficiency Condition, and
  2. reevaluate scheduled maintenance.
  3. Remove generation capacity limitations where practical.
  4. Return transmission facilities to service where capacity or interchange conditions can be improved.
  5. Synchronize all available generating facilities, holding fast-starting peaking units in a standby state,if appropriate.
  6. Make arrangements to purchase power.

II. Alert Condition

- A. (Deficient system) If OR is less than 75 percent of the minimum requirement,
  1. Declare a [region] Alert condition, and
  2. Perform the steps under I.B.
  3. Institute effective voltage reduction procedures, curtailment of interruptible loads, or both.
- B. (All systems) When the OR is below 65 percent of the minimum requirement, institute effective voltage reduction procedures, curtailment of interruptible loads, or both.
- C. When OR cannot be restored to above 75 percent of the minimum requirement, neighboring systems are required to exchange information on their respective OR status to arrange transaction schedules to improve overall reliability.

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[17] An emergency is any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system. [19]

5.0 OPERATIONAL EXPERIENCE

NUREG-1032 divides operational experiences into three types: (1) plant-centered events which had an impact on the availability of offsite power, (2) grid blackouts or perturbations which had an impact on the availability of offsite power, and (3) weather-related and other events which had an impact on the availability of offsite power. Category 1 is not addressed in this study. Category 3 was separated into weather-related events and other events which perturbed the grid.

5.1 Grid Blackouts or Perturbations Which Impacted Nuclear Plants

For the purpose of this study, the switchyard is considered to be a component of the grid.

> In 1989, at Virgil Summer, technicians working in the generator stator cooling controls caused a loss-of-stator-cooling signal to be generated although stator cooling was not lost. The turbine tripped and the reactor scrammed. The nearby plants which attempted to make up the load tripped because their generator protection was set high because of their age. The cascading failure resulted in 16 units offline and a severely depressed voltage throughout South Carolina and neighboring States. Virgil Summer's 1E (safety-related) busses saw the degraded grid condition and isolated from the grid. The emergency diesel generators (EDGs) started and loaded the 1E busses. [LER 50-395/89-012]
>
> Also in 1989, a breaker failure in the switchyard of the Dresden site caused a partial loss of offsite power (LOOP)[18] and a loss of annunciators on Unit 2 which led to the declaration of an alert. Unit 3 scrammed. The event was complicated by equipment losses and failures on both units. [LER 50-249/89-001]
>
> In 1989, a failure of a lightning arrestor at LaSalle 2 caused a scram on LaSalle 1, a partial LOOP, multiple complications on both units which led to the declaration of an alert and propagated to Braidwood where both units saw a voltage drop. [LER 50-373/89-009; LER 50-456/89-003]
>
> In 1992, a breaker fault at Sequoyah 1, complicated by preexisting conditions and human error, resulted in a dual-unit scram, LOOP, natural circulation, EDG start and load, and actuation of the ice condenser. The local grid was depressed but not disrupted by the loss of Sequoyah's output. [LER 50-327/92-027]
>
> At various times, insulators contaminated by sea salt, bird droppings, blown dust, etc. have caused line faults which caused transients at Pilgrim, Comanche Peak 1, and Diablo Canyon.

---

[18] A loss of offsite power is loss of all normal AC power, both 1E and non-1E components.

In 1994, a main transformer failure at Beaver Valley 1 caused a reactor scram. The reactor scram caused a local grid perturbation which led to the scram of Unit 2 and a LOOP on Unit 2. [LER 50-334/94-005]

On December 14, 1994, a line fault caused by a contaminated insulator flashing over in a heavy fog on the Midpoint-Borah-Adelaide (Utah) 345 kV line tripped the line. Problems were also experienced on other transmission lines in the area. Diablo Canyon Units 1 and 2 saw undervoltage on the reactor coolant pump busses and the reactors were automatically scrammed in anticipation of reactor coolant pump trip. See AEOD/T95-01 for details.

In 1995, a series of equipment failures at nearby substations caused both Limerick units' generator protective relays to isolate from the grid causing the reactors to scram. The PECO system experienced the loss of eight transmission lines and the Eastern grid experienced a brief frequency transient. [LER 50-352/95-002]

On July 2, 1996, a transmission line sagged into a tree in Idaho creating a ground fault which progressed into a major fault on the Western Interconnection. Again, the nuclear plants saw a frequency transient but did not scram or lose offsite power. A similar event occurred the next day but did not propagate outside Idaho. [24]

On August 10, 1996, a line sagged into a tree again, this time in Oregon. The subsequent transient resulted in the loss of over 30,000 MW of load, 25,000 MW of generation, which is 17% of the total western U.S.-Canada generation, and the tripping of 190 generating units including both Diablo Canyon Units and Palo Verde Unit 1 and Unit 3. [25]

Diablo Canyon declared the normal 500 kV offsite power source inoperable. Both Units transferred to the alternate offsite power source. [LER 50-275/96-012]

Palo Verde did not lose offsite power. [LER 50-528/96-004]

Factors which contributed to the incident were high transmission loads and equipment out of service. WSCC NW has a winter peak and summer is outage season. California was suffering a lengthy hot spell and less expensively produced hydro-electric power was available. [25]

From a DOE database [26], information on grid disturbances reported from 1985-1993 shows the disturbances to be caused by downed lines, equipment outages, demand management, and other causes. Storms were the principal initiators of disturbances, followed by equipment failure, ambient temperature, sabotage, fire, and other causes. Figure 5.2.1 illustrates this distribution.

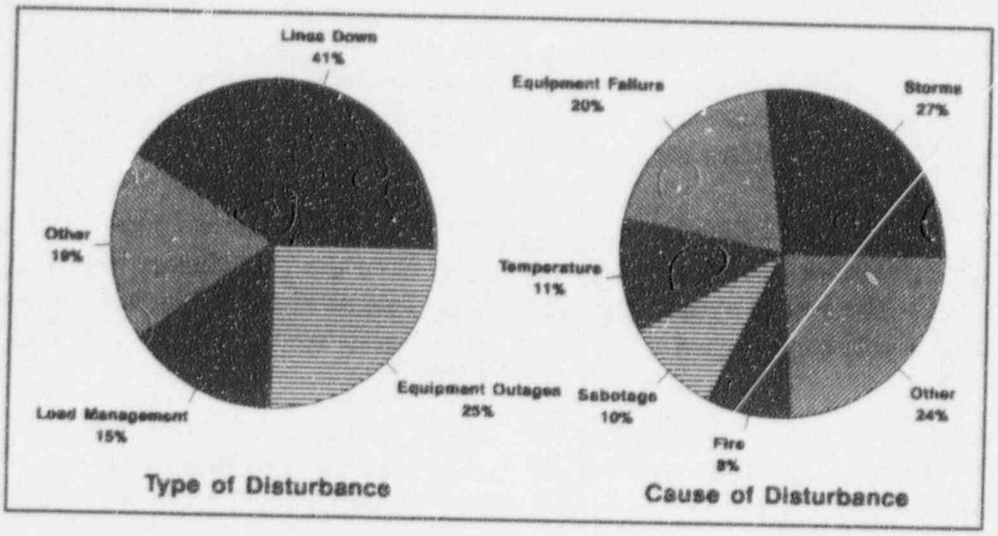

Figure 5.2.1: Grid Disturbances [26]

5.2 Weather-Related Events Which Have Perturbed the Grid

Weather-related events have impacted the availability of offsite power. Most weather-related events not associated with Hurricane Andrew[19] were caused by lightning.

Crystal River 3 had a LOOP in 1989 with one EDG out for maintenance when lightning destroyed a current transformer. One 1E bus was without power for two minutes. [LER 50-302/89-025]

Lightning struck a breaker at Waterford 3 in 1990, causing it to malfunction, explode, and burn. Because of preexisting conditions, the reactor scrammed on high pressure. One EDG started and loaded. [LER 50-382/90-012]

An alert was declared at Yankee-Rowe in 1991 when lightning destroyed a lightning arrestor and faulted a disconnect switch resulting in a turbine trip, LOOP, loss of

[19] Hurricane Andrew was a unique event of enormous impact; however it is not being addressed in this study because it has been the subject of Information Notice 93-053, "Effects of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned," and NUREG-1474, "Report on the Effects of Hurricane Andrew on Turkey Point Nuclear Generating Station from August 20 - 30, 1992."

communications, engineered safeguards features (ESF) actuation, and EDG start and load. [LER 50-029/91-002]

A complicated scram at Waterford 3 in 1991 was caused by lightning which caused a grid voltage transient. There was excessive cooldown of the reactor coolant system, manual ESF actuations, and multiple equipment failures. Offsite power was not lost. [LER 50-382/91-013]

In 1991, dual-unit scrams at Palo Verde 1 and 3 were caused by lightning which caused a three-phase fault without ground on a transmission line. There was no LOOP, but the EDGs did start. [LER 50-528/91-010]

Other recent dual-unit scrams caused by lightning occurred at Comanche Peak and Vogtle in 1995. Offsite power saw a brief frequency depression following each event, caused by the loss of generation. [LER 50-445/95-002] [LER 50-424/95-002]

5.3 Other Events Which have Perturbed the Grid

In 1989, during an intense solar magnetic disturbance, a severe grid disturbance occurred in a portion of NPCC in Canada. The storm was also implicated in the failure of two main transformers at Salem 1. Solar magnetic storms cause geomagnetically-induced currents (GIC) on Earth which can affect electrical equipment, particularly main transformers. Salem Units 1 and 2 and Hope Creek have reported ten main transformer failures since startup of Salem 1 in 1977, four of which are known to have been caused by GIC. The vulnerability of Salem and Hope Creek to GIC damage is unique among nuclear plants, but common to other types of power plants in areas known to be vulnerable to the effects of GIC. [27]

In 1989, a lineman working in the switchyard at Brunswick 2, grounded a potential transformer (PT) (which should never be grounded), thinking it was a current transformer (CT), the utility's standard. The resultant explosion vaporized the ground cable, punched a hole in the isolated phase bus duct, and caused a recirculation pump to trip. The reactor was manually scrammed to prevent operation in a region of potential core instability. A LOOP occurred and the EDGs started and loaded their 1E busses. [LER 50-324/89-009]

Several forest fires and brush fires have impacted the operation of the grid. Fires threaten equipment and personnel. Fires produce smoke which creates a lower resistance pathway between transmission lines, causing line faults.

In 1990, at Hope Creek, a brush fire near transmission lines resulted in a complicated scram but no LOOP. [LER 50-354/90-003]

In 1990, at Diablo Canyon, a forest fire caused a scram but no LOOP. In 1994, a forest fire caused a partial LOOP but no scram. [LER 50-275/90-015; 94-016]

In 1992, at Oyster Creek, a forest fire caused a LOOP and a complicated scram. [LER 50-219/92-005]

An earthquake caused a partial LOOP in 1992 at Humboldt Bay, which was in a SAFSTOR condition (permanently shutdown, but with fuel in the spent fuel pool) [LER 50-31/92-002].

On January 17, 1994, an earthquake struck southern California. At that time and for that reason, the grid in the western states began to separate. The western grid separated into north and south islands. The frequency in the south island increased and some loads were lost. Transmission lines tripped and generating units tripped or reduced power. Diablo Canyon, in the north island, experienced low frequency. WNP 2 was also in the north island. Operating nuclear plants in the south island which experienced high frequency were San Onofre and Palo Verde. See AEOD/T94-01 for details. On the other hand, the Loma Prieta earthquake in 1989 did not cause grid disturbances outside a limited area. The damage to the grid caused by an earthquake is determined by the strategic importance of the equipment involved.

6.0 POTENTIAL PROBLEMS WITH GRID STABILITY

6.1 Normal Contingencies

Reliability Councils' minimum criteria for stability require the grid to be operated in a stable manner during and after normal contingencies[20]. NPCC[21] requires stability of the bulk power system to be maintained during and after the most severe of the contingencies listed in Table 6.1. [7] Stability analyses to ensure adequate transmission capability are performed to satisfy the Reliability Councils' criteria. Offsite power availability is related to grid conditions, but the stability analyses done to ensure adequate transmission capability do not necessarily give sufficient assurances that offsite power to nuclear plants will be adequate at all times, as Section 6.3 demonstrates.

Table 6.1: Normal Contingencies [7]

1.	A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing
2.	Simultaneous phase to ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower.
3.	A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing
4.	Loss of any element[22] without a fault
5.	A permanent phase to ground faul[illegible] circuit breaker, with normal fault clearing
6.	Simultaneous permanent loss of both poles of a direct current bipolar facility
7.	The failure of a circuit breaker associated with an S[pecial]P[rotective]S[ystem] to operate when required by the following: loss of any element without a fault; or a permanent phase to ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section

6.2 Severe Contingencies [7]

Other contingencies with more severe consequences for the grid are listed in Table 6.2. These are considered unpredictable and steps to reduce their probability of occurrence are recommended by the Reliability Councils as well as measures to mitigate those consequences should the event occur. Analyses of these contingencies to determine their effects are being

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20 The term "normal contingency" defines conditions under which the stability of the bulk power system must be maintained. The term "severe contingency" describes conditions under which the stability of the bulk power system cannot be guaranteed.

21 Specific Regional information is sometimes given as representative of all Regions. While it may [illegible]presentative, there may be differences in Criteria from Region to Region. Information on the same subject for Regions other than the one named should be obtained from the Criteria of that Region.

22 An element is any electrical device with terminals which may be connected to other electrical devices; usually limited to a generator, transformer, transmission circuit, an HVDC pole, braking resistor, a series or shunt compensating device, or bus section. [19]

conducted by the utilities. System stability is *not* assured during these severe contingencies. Adequate offsite power under these circumstances is best assured by preventing the severe contingency from occurring (as demonstrated in Section 6.3).

Table 6.2: Severe Contingencies [8]

1.	Loss of entire capability of a generating station
2.	Loss of all lines emanating from a generating station, switching station or substation
3.	Loss of all transmission circuits on a common right-of-way
4.	Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed fault clearing and due regard to reclosing facilities
5.	The sudden drop of a large load or major load center
6.	The effect of severe power swings arising from outside the Council's interconnected systems
7.	Failure of a special protection system, to operate when required following normal contingencies
8.	The operation or partial operation of a special protective system (SPS) for an event or condition for which it was not intended to operate

6.3 Potential Problems

Four reports of potential problems related to grid stability were found in which licensees reviewed stability analyses and instabilities were discovered. The reviews were done as a followup of Information Notice 89-83, "Sustained Degraded Voltage on the Offsite Electrical Grid and Loss of Other Generating Stations as a Result of a Plant Trip," in response to a question raised during an electrical distribution functional inspection, and following actual events. The reports are summarized in Table 6.3 and a more detailed event description is given in Sections 6.3.1 through 6.3.4.

Table 6.3: Grid Instabilities Discovered by Plant Analyses

PLANT	DATE	PROBLEM
ANO 1	10/5/91	During peak summer loads, if both units were off line and the 500-kV auto-transformer was unavailable, the 161-kV offsite power source might not be able to maintain adequate voltage to ANO loads during accident conditions.
Haddam Neck Millstone 1,2,&3	4/15/92	With the Millstone units at full power, the grid lightly loaded, and a heavy flow of power from the east to the west, certain ground faults could cause the loss of the local grid and trip the Millstone units.
Salem 1&2 Hope Creek	6/2/87 9/27/92	Necessary to reduce power on Salem and Hope Creek units when severe weather is in the area to avoid grid instability should a unit scram. Necessary to trip a unit if the Deans 500-kV line is out of service and the Keeney line is lost.
Point Beach 1&2 Kewaunee	10/12/91 3/28/93	Two scenarios involving transmission line outages with the potential to cause loss of all offsite power to Kewaunee were identified. Two instances occurred when Kewaunee and one Point Beach unit were off line and the licensee for Point Beach requested technical specifications (TS) surveillance relief to avoid the possibility of tripping the second Point Beach unit and causing grid degradation.

6.3.1 ANO 1: Inability of 161-kV Offsite Power Source to Maintain Adequate Voltage

During the review of Information Notice 89-83, "Sustained Degraded Voltage on the Offsite Electrical Grid and Loss of Other Generating Stations as a Result of a Plant Trip," for applicability to ANO, licensee engineers found that offsite grid loading on the 161-kV system had increased to the point where reanalysis was necessary to determine the system's capability to supply adequate offsite power to ANO. The licensee determined that, with Units 1 and 2 shut down during expected summertime peak loads, the 161 kV system could not provide adequate offsite power to ANO should the 500-kV auto-transformer become unavailable.

The degraded grid voltage analysis accepted by the NRC in 1979 was not updated because no requirement for periodic update existed. The transmission planning engineers recommended necessary improvement on the transmission system to maintain adequate voltage on the system. The offsite voltage criteria for ANO were more restrictive than the transmission system criteria; therefore, the ANO offsite voltage requirements were not met.

Procedural requirements were established to maintain adequate offsite power to ANO until permanent arrangements could be made. Transformer tap changers and capacitor bank installation were completed in 1992. [LER 50-313/91-010]

6.3.2 Millstone 345-kV Instability

Following an electrical distribution system functional inspection, the NRC requested that Northeast Utilities (the licensee for the Millstone and Haddam Neck units) provide the results of a simulation of a three-phase fault with delayed clearing due to a breaker failure with a transmission circuit out of service. Northeast Utilities performed several simulations in order to show that, although stability could not be maintained during the event as suggested by the NRC, the system could maintain stability following all normal contingencies and all extreme contingencies that involved a breaker failure at Millstone. The previous study, done in 1979 and thought to remain valid for current conditions, showed that stability could be maintained. The simulations showed instability.

At this point, Northeast Utilities reviewed system stability. Part I of the review concentrated on simulating the normal contingencies listed in Table 6.1. They found that an output of Millstone of 2680 MW could no longer be properly supported by the grid under light system loading conditions. Retiring uneconomical smaller units following the addition of larger resources including the Seabrook nuclear plant (1150 MW), non-utility generators (2000 MW), and the Phase II High Voltage Direct Current (HVDC) Interconnection (2000 MW) to Hydro Quebec concentrated generation in the Millstone area above the level that could be supported by the rest of the system should a normal contingency occur.

The Millstone station output interface, composed of four circuits which are the only connection between Millstone and the grid, is critical to the stability of Millstone operations. A scheme called "severe line outage detector" (SLOD), an SPS, trips either Units 1, 3, or both following a loss of three of the transmission lines from the station. The 1979 study showed that the SPS in service was sufficient to eliminate stability concerns. The 1992 study showed that with all critical systems elements (generation units, etc.) in service, stability problems exist unless there are limits on the amount of generation from the Millstone units. That amount of generation was determined to be 2620 MW.

With one critical systems element out of service, a stability problem existed. The two most severe contingencies that experienced instabilities required that Millstone output be reduced to 1870 MW to achieve stability. The change in system response from 1979 to the present was in the output routing of a single, large, fossil-fueled unit. [LER 50-245/92-020]

6.3.3 Salem and Hope Creek Transmission Line Outage Problems

In 1987, a barge accident on the Delaware River damaged or destroyed several towers on the Keeney transmission line. Since the line was expected to be out of service for a year, the licensee developed a scheme designed to eliminate possible instabilities that might occur because that line was out of service. A stability analysis showed that with all three units operating at 75-percent power when the Deans 500-kV line faulted, stability problems would develop on all three units (Salem 1 and 2 and Hope Creek), causing them to trip. The

analysis showed that all three units could be operated safely at full power with output on three lines, provided Salem 1 was tripped when the Deans line experienced an outage.

The trip-a-unit scheme was supposed to be in operation when all three of the units were operating above 75-percent power. During lightning or thunderstorm activity in the area, power would be reduced below 70 percent and the trip-a-unit scheme would be defeated. In June 1987, the scheme's operation was verified, when an unexpected lightning strike near the Deans switching station actuated the trip-a-unit scheme. Salem 1 tripped from 100 percent power. [LER 50-272/87-007]

In September 1992, the trip-a-unit scheme was again initiated when the Deans line was removed from service for about one month. Salem 1 would have been tripped if the Keeney line experienced an outage.

6.3.4 Kewaunee/Point Beach 1 and 2 Transmission Line Outage Problems

The Kewaunee unit and the two Point Beach units are located, as shown in Figure 6.4.1, on Lake Michigan, about 75 miles north of Milwaukee, Wisconsin.

Two specific problem scenarios have been identified at Kewaunee for which corrective responses have been identified. In scenario A, with Kewaunee at maximum output, and line Q-303 out of service, line R-304 trips. Kewaunee must back down 10 MW to avoid grid instabilities which could cause the generator to become unstable. The resultant generator instability could cause the loss of F-84 and Y-51, the remaining transmission lines. At 40 percent power with Q-303 out of service, when R-304 trips, Kewaunee must back down 20 MW to avoid grid instabilities, generator instability, and loss of all offsite transmission lines.

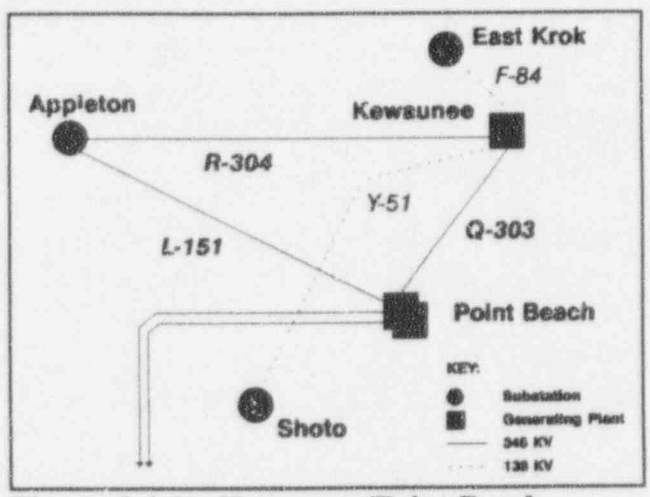

Figure 6.4.1: Kewaunee/Point Beach Transmission Lines [5]

In scenario B, with Kewaunee at 100 percent power, transmission line L-151 is out of service and R-304 trips. No grid instabilities occur. At light load conditions (40 percent power), Kewaunee must back down 20 MW to avoid possible grid instabilities, generator instability, and loss of all offsite transmission lines.

Although Kewaunee is more vulnerable, having fewer offsite transmission lines, Point Beach is also susceptible to similar grid instabilities. With Kewaunee in an outage and one Point Beach unit off line, a loss of the remaining operating unit during normal weekday loading would likely result in a degraded voltage condition to the extent that both Point Beach units

and Kewaunee 1E busses would isolate from offsite power and would transfer to their EDGs. Both licensees have taken steps to avoid having all three units off line simultaneously. They also took steps to compensate for the loss of generation should all three units be offline in order to assure grid reliability. Barring another complication, the MAIN WUM area would not experienced a blackout, according to the licensee for Point Beach.

The size of the three plants (not large for nuclear plants, but much larger than other generating units in the area) and the remoteness of the sites are major contributors to the potentials for instabilities that exist. [LER 50-305/94-010]

6.4 The Changing Grid

Certain emerging issues appear to offer a challenge to the reliability of the grid in the not-too-distant future: independent power producers and restructuring. Detailed discussions of these emerging issues are beyond the scope of this study. They are introduced in the following paragraphs.

6.4.1 Independent Power Producers

In November of 1978, the Public Utility Regulatory Policies Act (PURPA) was enacted. The number of facilities producing electricity for their own facilities and selling the remainder (cogeneration) and those producing electricity for sale to consumers (non-utility generators or small power producers) increased afterward, as a result of the favorable treatment in PURPA, among other things.

Maintaining reliability of the bulk power system while integrating these independent power producers (IPPs) as they are collectively called, is being addressed by NERC and its member Councils. [28]

6.4.2 Restructuring of the Electric Industry

As a result of the passage of the U. S. Energy Policy Act of 1992, the Federal Energy Regulatory Commission adopted "Promoting Wholesale Completion Through Open Access; Non-Discriminatory Transmission Services by Public Utilities," on May 10, 1996. It was formerly cited RM94-8.3GO; the current citation is Order 388. This document has become the basis for what is being called "restructuring." The electric industry is undergoing substantial changes, the nature of which is unfolding. How the reliability of offsite power to nuclear plants, in particular, will be affected is yet to be determined.

7.0 ANALYSIS

7.1 Regulatory Background

Nuclear plants need power to cool the reactor core whether or not the plant is producing power. Consequently, the reliability of offsite power is important to nuclear safety. In 1979, the NRC identified the loss of all AC electrical power to the nuclear plant, called station blackout, as an unresolved safety issue.

7.1.1 Unresolved Safety Issue A-44: "Station Blackout"

Station blackout is the complete loss of AC electrical power in a nuclear power plant. Because many safety systems required for removing decay heat from the reactor core and containment depend on AC power, the consequences of a station blackout could be severe. Station blackout was shown to be an important contributor to the total risk from nuclear power plant accidents. Additionally, operating experience raised concerns that the reliability of both the onsite and offsite emergency AC power systems might be less than originally anticipated.

In 1979, the NRC designated station blackout as an unresolved safety issue and task action plan A-44 was issued in July 1980. The final report on USI A-44 appeared in NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," dated June 1988.

7.1.2 10 CFR 50.63: "Loss of all alternating current power" [29]

10 CFR 50.63 was adopted in 1988 to implement the resolution of USI A-44. It requires that "Each light water-cooled nuclear power plant licensed to operate must be able to withstand for a specified duration and recover from a station blackout as defined in § 50.2. {q.v.} The specified station blackout duration shall be based on the following factors:

(i) The redundancy of the onsite emergency ac power sources;
(ii) The reliability of the onsite emergency ac power sources;
(iii) The expected frequency of loss of offsite power; and
(iv) The probable time needed to restore offsite power."

Implementation of this section was not required for plants licensed before July 21, 1988, if the capability to withstand station blackout was specifically addressed in the operating license proceeding and was explicitly approved by the NRC. Other plants licensed prior to July 21, 1988 and facilities licensed after that date were required to make submittals addressing the factors as listed in the regulation.

7.1.3 Regulatory Guide 1.155: "Station Blackout" [30]

This regulatory guide described a means acceptable to the NRC staff for meeting the requirements of §50.63 of 10 CFR Part 50. The regulatory guide further defines station blackout as the "complete loss of all alternating current electric power to the essential and nonessential switchgear buses in a nuclear power plant." This loss included the loss of offsite power, turbine trip, and failure of the onsite emergency AC power system (usually the EDGs), but not the AC power to busses fed by station batteries through inverters or the loss of AC power from "alternate ac sources."

7.2 Global Factors

The factors which affect the availability of offsite power and are common to all plants are called "global factors." Among the global factors are demand, generation/capacity, capacity margin, and age.

Nuclear plants have been well insulated from the effects of high demand; however, in the Virgil Summer event, high demand was named as a contributor to the grid degradation that caused the 1E busses to isolate from the grid. Also, in the August 10, 1996, Western Grid disturbance high levels of demand contributed to the initiation of the event. Peak demand projected for 10 years in each region of NERC shows a steady increase as shown in Appendix A. Low capacity margins indicate that a potential for problems does exist. The insulation of nuclear plants from the effects of excess demand may be eroded in the future.

Plant age averages 38 years. With 38.2 percent of the U.S. electricity generated by plants 26 years or older, age has the potential to become a factor in grid stability.

7.3 Specific Factors

Factors which are specific to a plant or an area are called "specific factors." Among the specific factors are size, ability to isolate a fault, ability to purchase power, weather effects, and transmission load dynamics.

7.3.1 Size

Plant size caused a large load to be shifted to much smaller non-nuclear plants in the Virgil Summer event in 1989 and two separate events at Palo Verde 1 in 1989. The average nuclear plant size is 957 MWe, while the average steam-fired plant size is only 200 MWe. Loss of a nuclear unit, therefore, drops a very large load on nearby units. Loss of two nuclear units at one site simultaneously is a severe strain on the grid's resilience. Of the numerous dual unit scrams which have occurred (and one four-unit scram), only the WSCC events of December 14, 1994, in which both Diablo Canyon units scrammed, and August 10, 1996, in which both Diablo Canyon units and Palo Verde Units 1 and 3 scrammed, contributed to a major grid disruption.

7.3.2 Ability to Isolate a Fault

The Waterford event in 1990 involved a fault that propagated from offsite to Waterford. Waterford scrammed and a cascading failure due to declining voltage occurred which was recorded at River Bend. LaSalle and Braidwood are connected by two 235 kV lines for one site to supply offsite power to the other. The lines also propagate grid disturbances from one to the other.

7.3.3 Plant(Area)-Specific Vulnerabilities

Because their initial stability analyses were not required to be updated, ANO, Millstone, and Salem/Hope Creek sites became vulnerable to certain potential instabilities as detailed in Section 6. In NPCC NE, smaller, less-efficient plants were retired when plants like Seabrook and Millstone 3 came on line. Many changes in the grid which affect its reliability can go unnoticed in the absence of a challenge. Without regulatory requirements to update their stability analyses, the licensees mentioned in Section 6 were motivated to reexamine their stability analyses by an information notice, electric distribution system functional inspections, and by events.

8.0 FINDINGS AND CONCLUSIONS

8.1 General Findings

The condition of the grid is dynamic: capacity changes; demand changes; transmission patterns change; equipment ages; new equipment is brought on line; and equipment is retired. Two relatively new factors are emerging: independent power producers and restructuring of the electric industry.

NERC has adopted programs and procedures to deal with forecasting, normal operations, emergency conditions, and recovery from system collapse. The programs and procedures as detailed in the various referenced documents appear to give a basis for assurance of orderly operation.

8.2 Specific Findings

The study findings are as follows:

(1) Demand will continue to increase yearly at a rate which will exceed the rate of increase of capacity growth further reducing capacity margins. Reducing capacity margins tends to increase the chance of instabilities.

(2) Average plant age will tend to increase as older plants will have to remain on line to make up for the diminishing reserves. Schemes to protect the integrity of an aging generator may increase the potential for grid instabilities. Increases in outage occurrences and duration may occur due to increased equipment failure due to aging.

(3) The 1979 stability analyses conducted to meet NRC requirements demonstrated adequate offsite power for nuclear plants in 1979. Most plants' stability analyses may not have been updated since then.

8.3 Conclusion

The "grid," the bulk power supply, as managed by the North American Electric Reliability Council member utilities, has adequate resources to give reasonable assurance that the reliability of the system will be maintained under normal conditions. On the whole, the grid is stable and reliable. Problems described in the Regional assessments as indicated in Section 4 as well as uncertainties introduced by restructuring of the electric industry indicate the need to monitor grid conditions on a regular basis.

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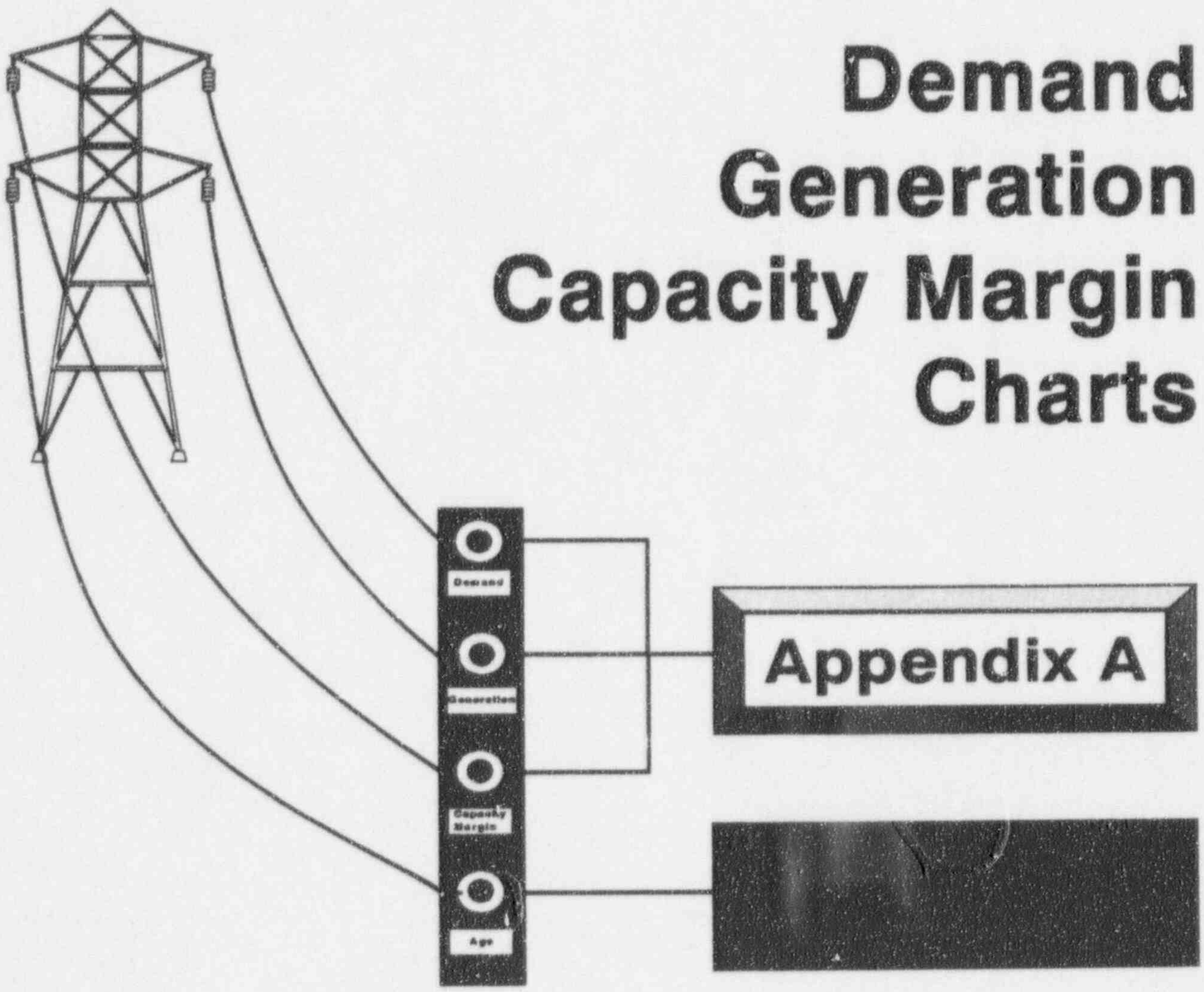
Appendix A

Demand Generation Capacity Margin Charts



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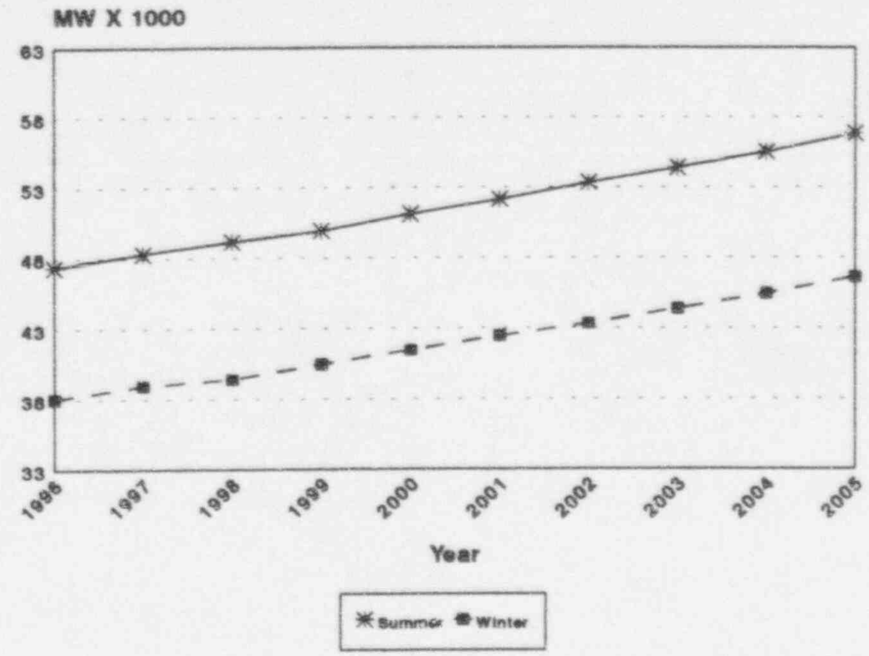

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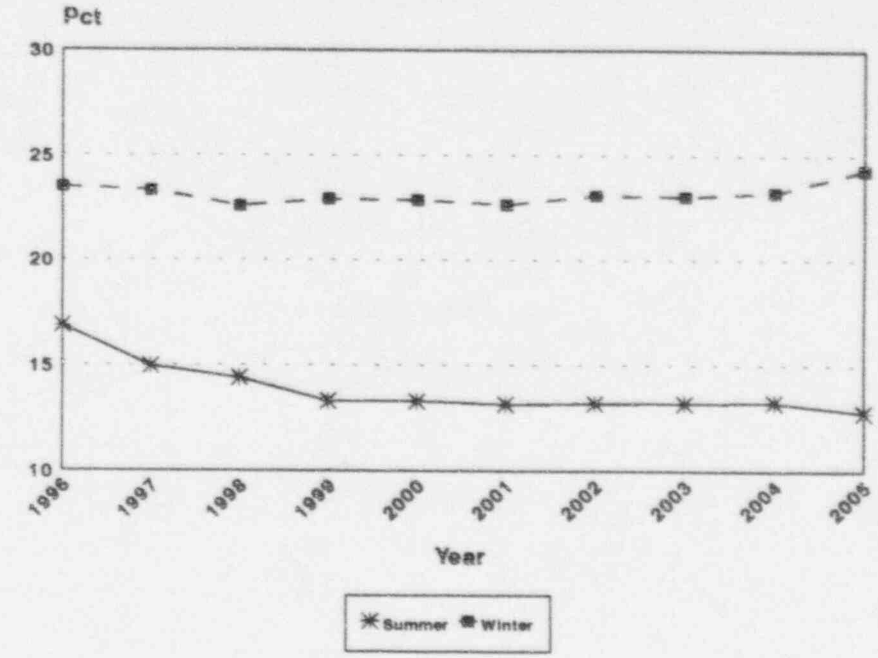

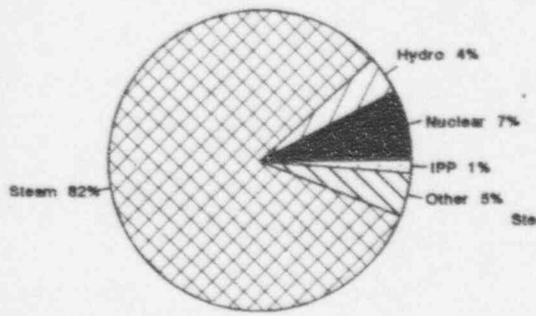

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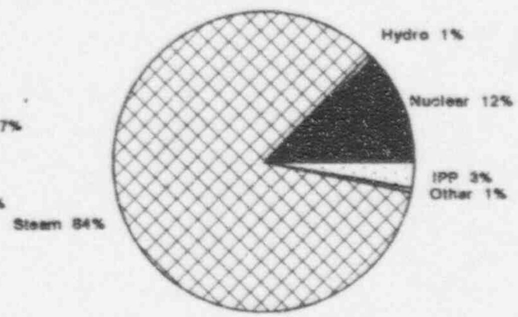
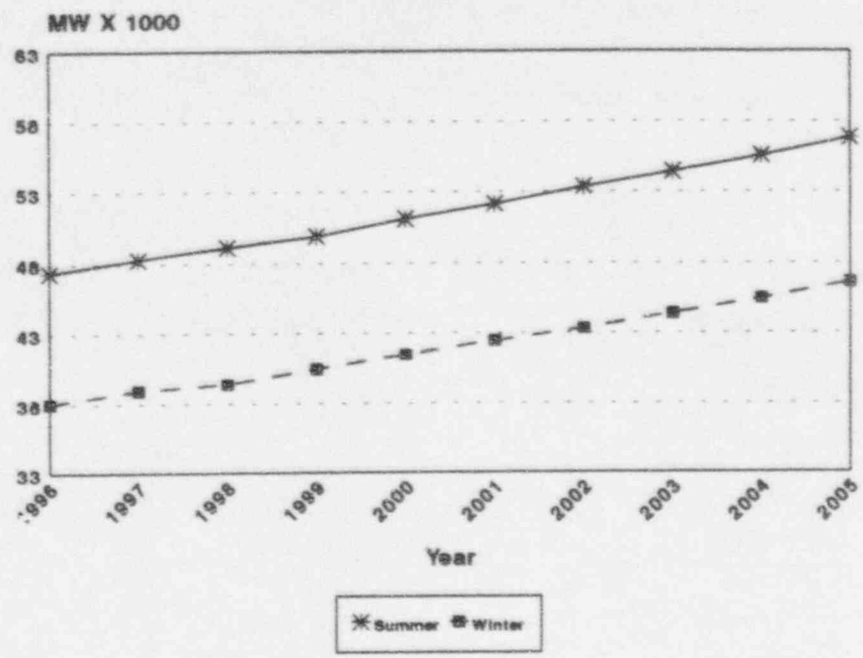


1995 Generation

ECAR

Beaver Valley 1 & 2
Big Rock Point
D. C. Cook 1 & 2
Davis-Besse
Fermi 2
Perry

Peak Demand for 10 Years



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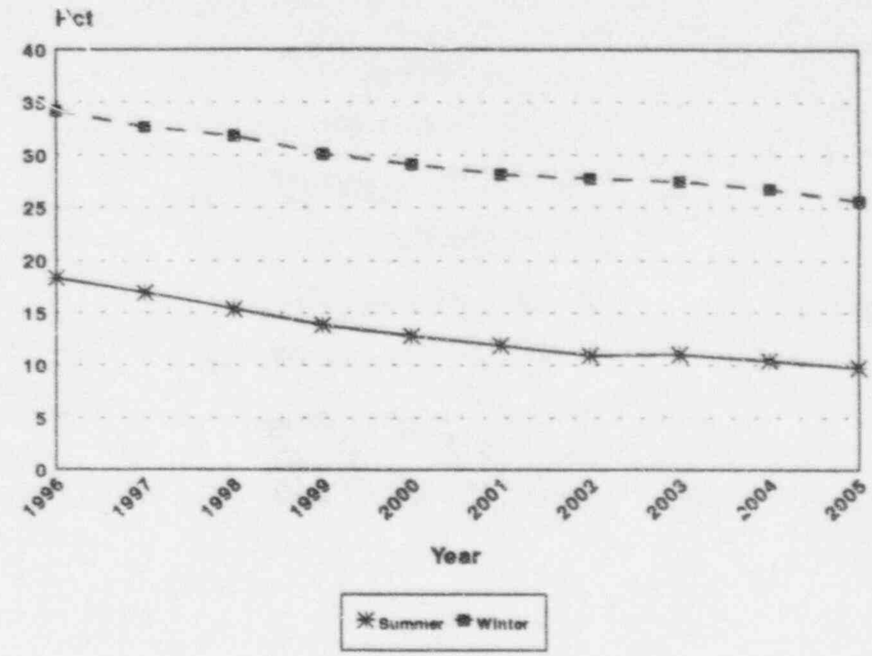

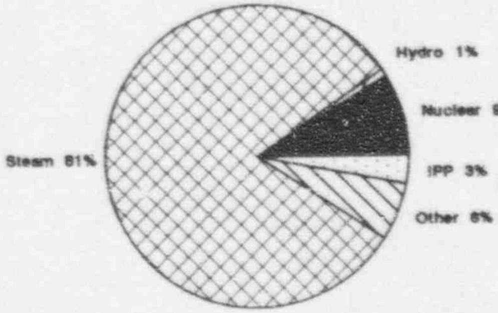

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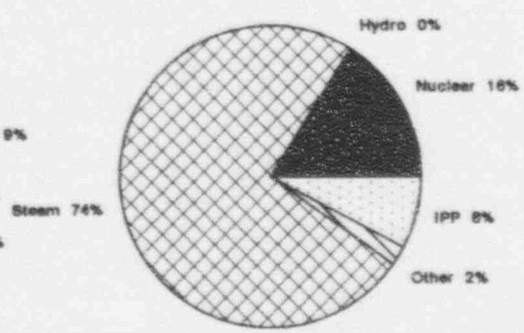
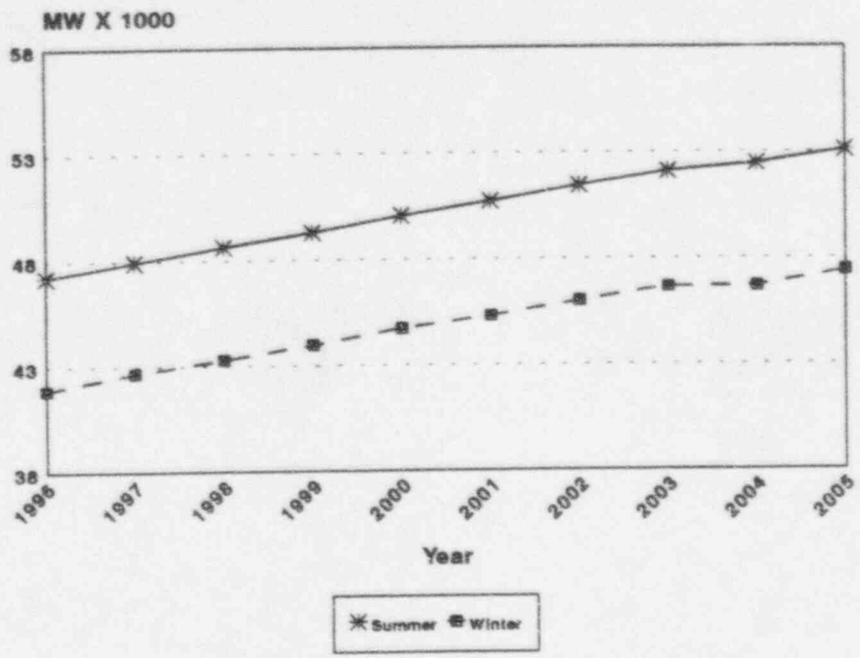


1995 Generation

ERCOT

Comanche Peak 1 & 2
South Texas 1 & 2

Peak Demand for 10 Years



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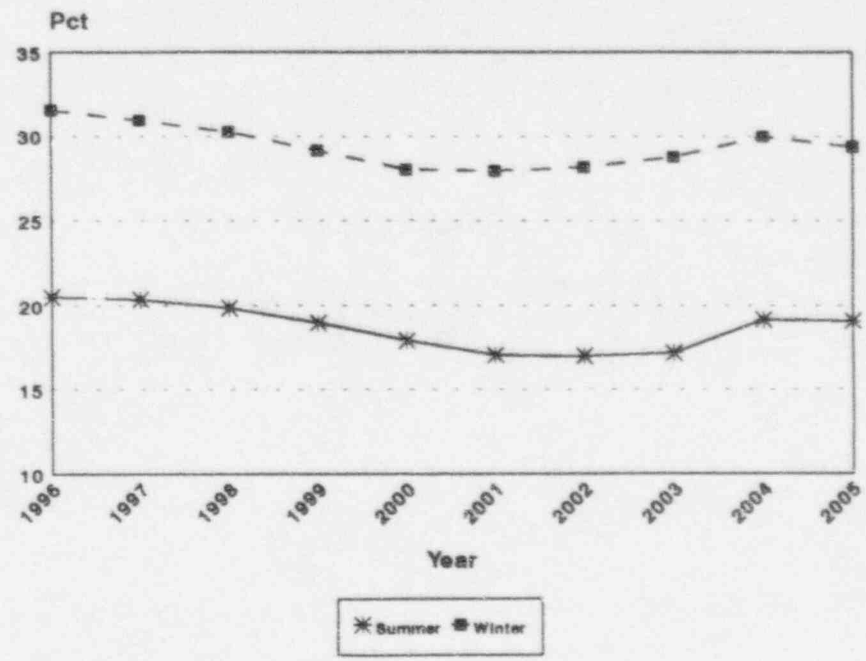

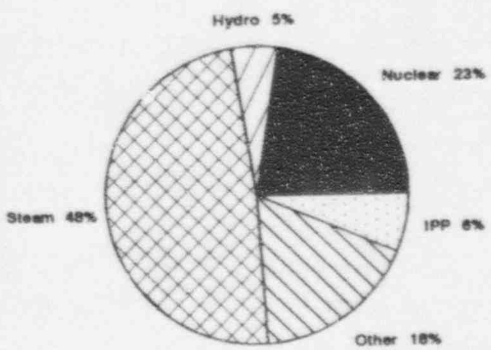

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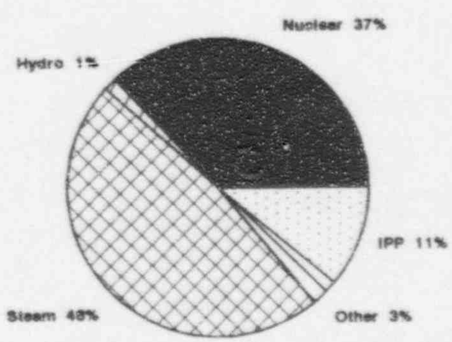
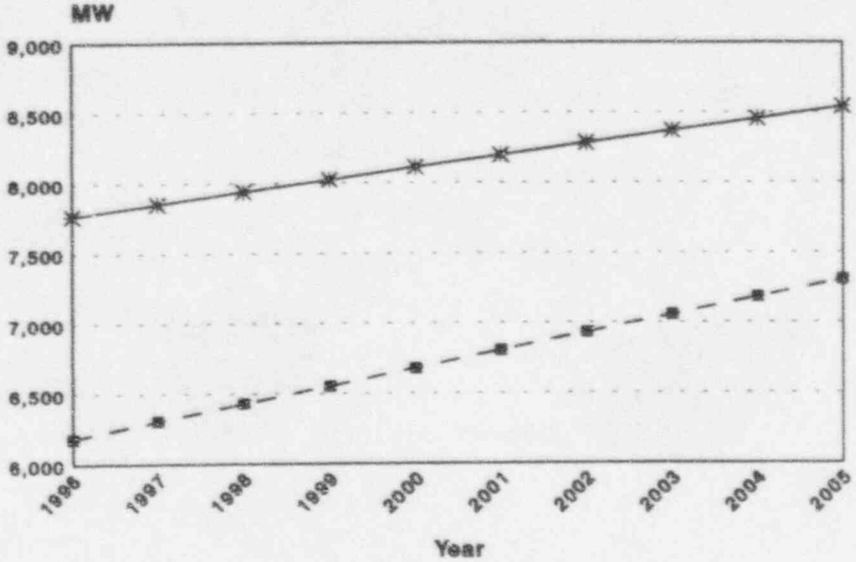


1995 Generation

MAAC

Calvert Cliffs 1 & 2
Hope Creek
Limerick 1 & 2
Peach Bottom 2 & 3
Salem 1 & 2
Susquehanna 1 & 2
Three Mile Island 1

Peak Demand for 10 Years



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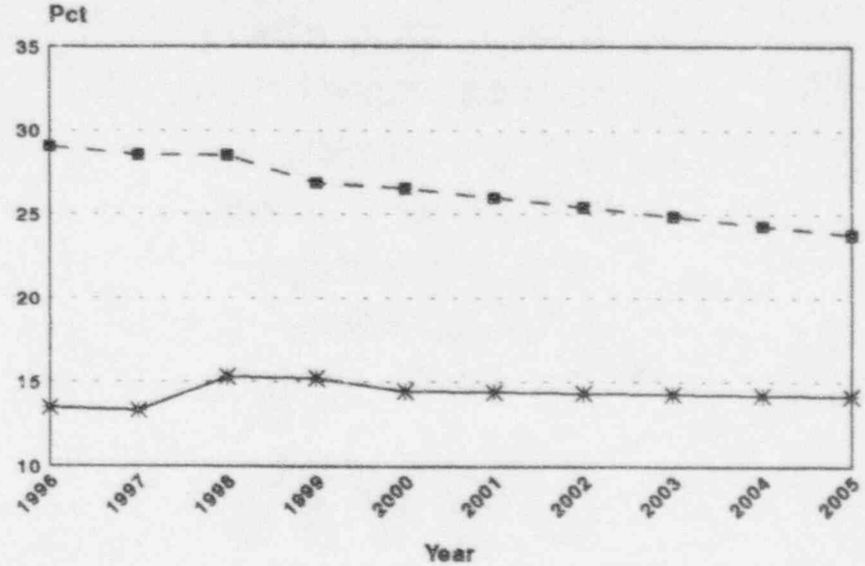

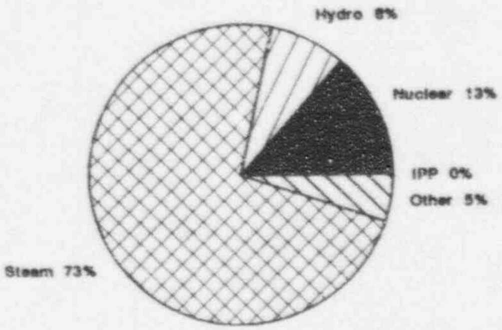

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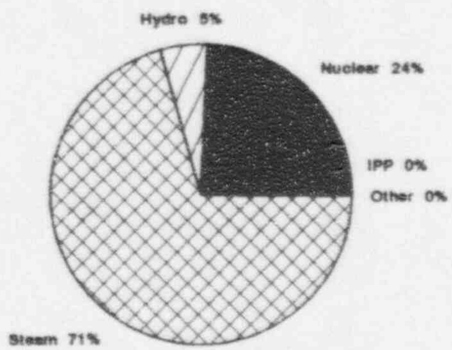
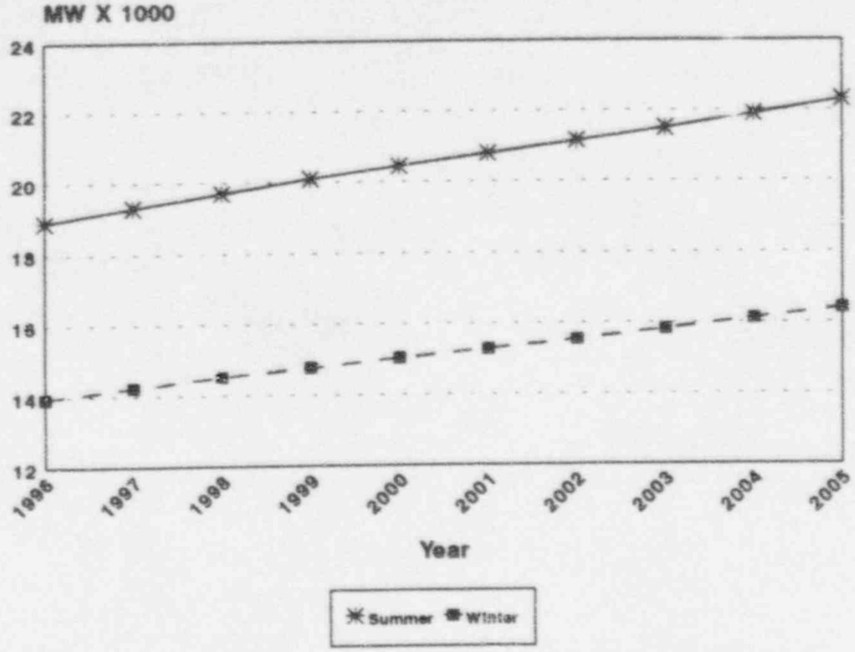


1995 Generation

MAIN EMO

Callaway

Peak Demand for 10 Years



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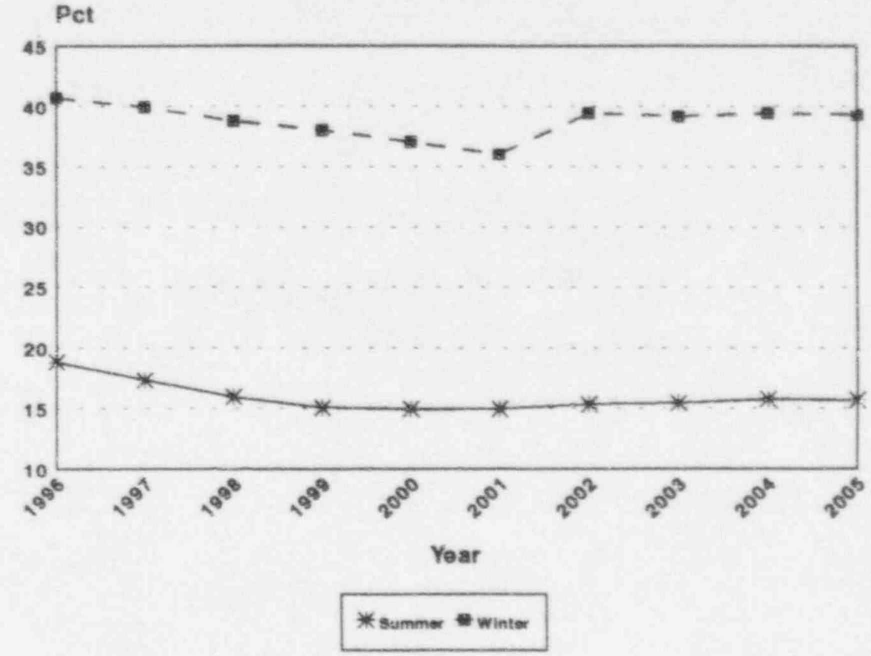
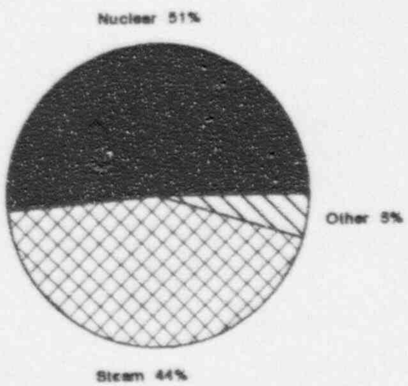
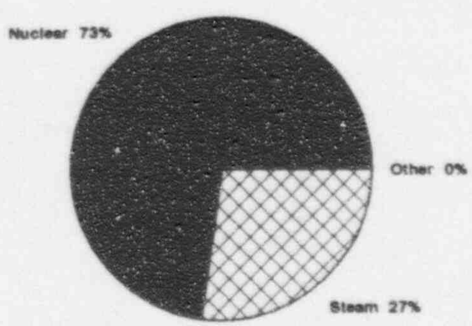




1995 Capacity

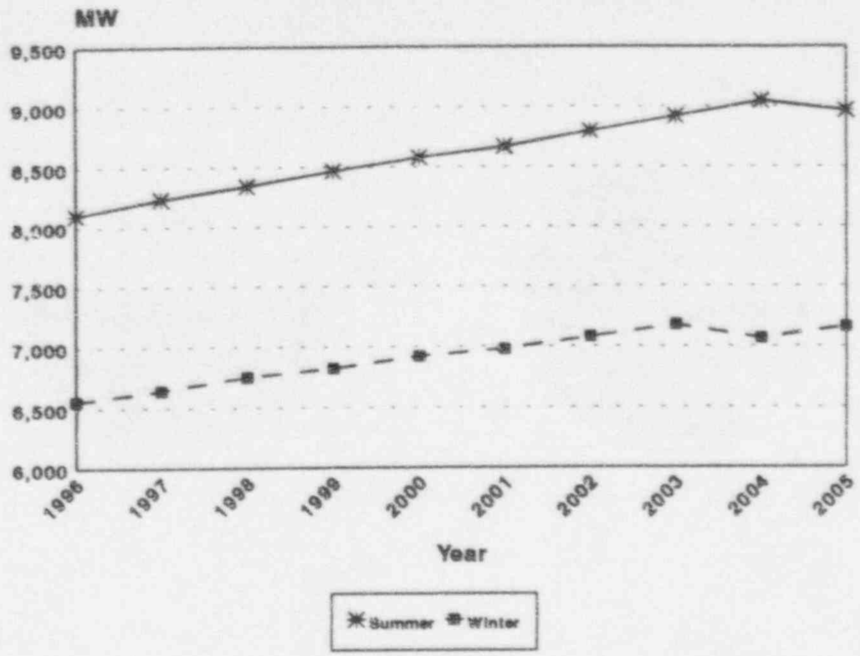


1995 Generation

MAIN NI

Braidwood 1 & 2
Byron 1 & 2
Dresden 2 & 3
LaSalle 1 & 2
Quad Cities 1 & 2
Zion 1 & 2

Peak Demand for 10 Years



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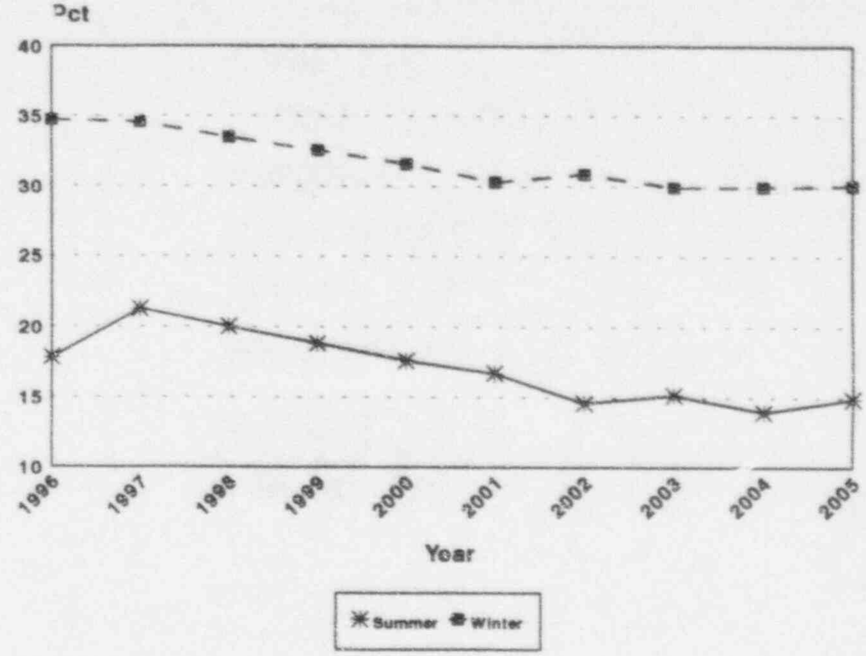

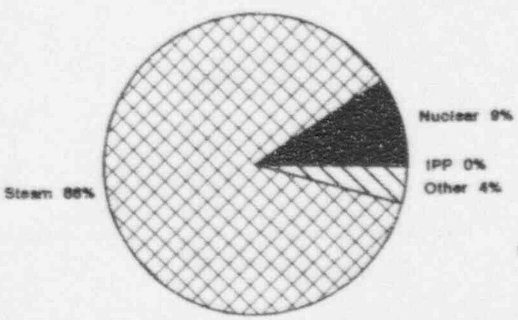

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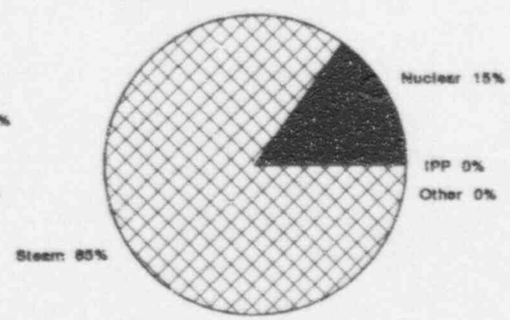
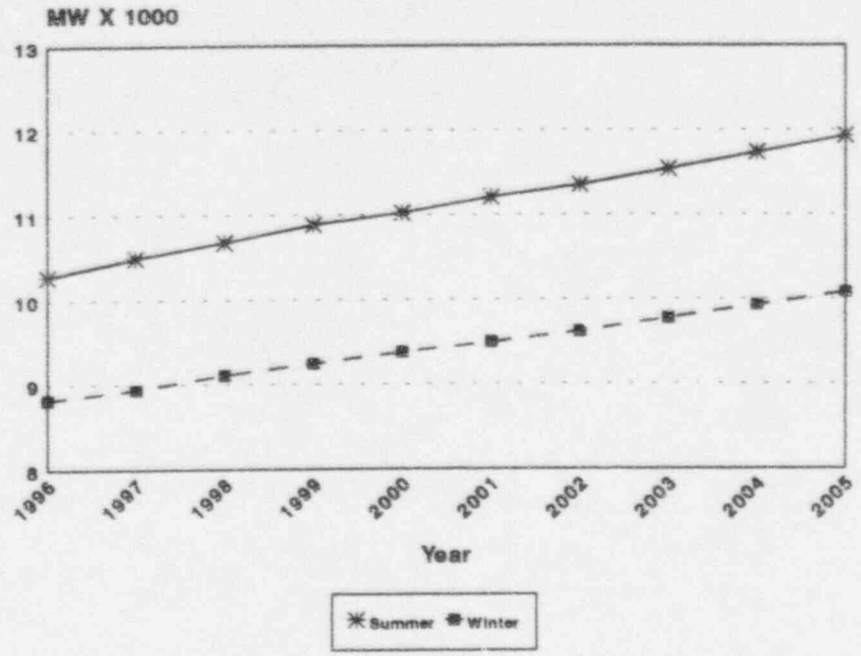


1995 Generation

MAIN SCI

Clinton

Peak Demand for 10 Years



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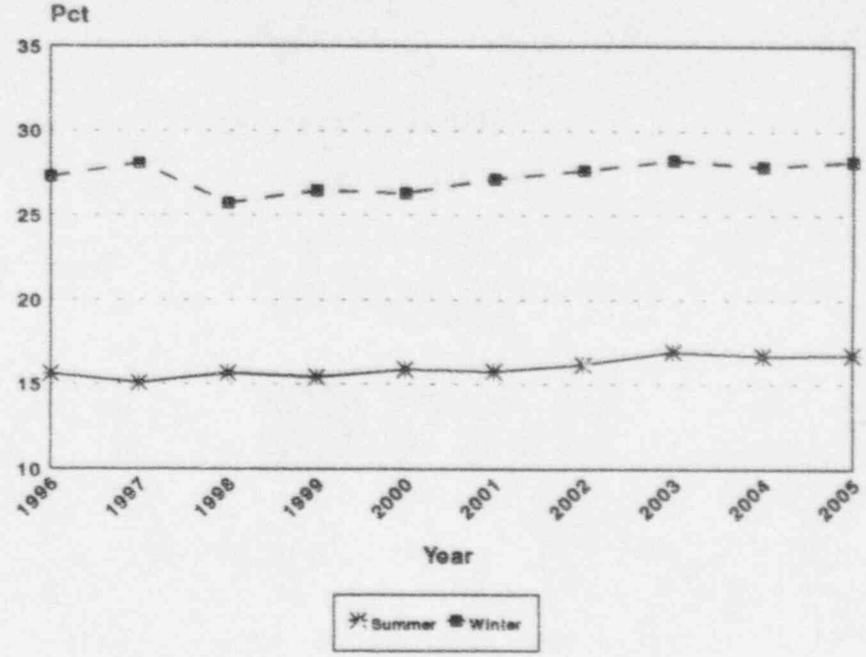

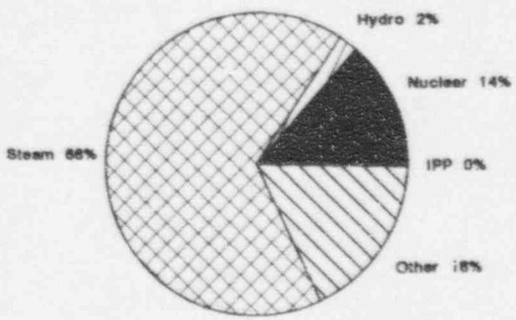

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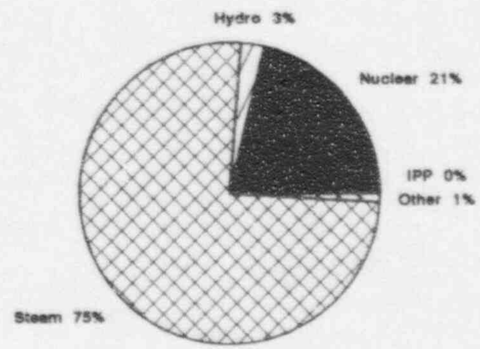
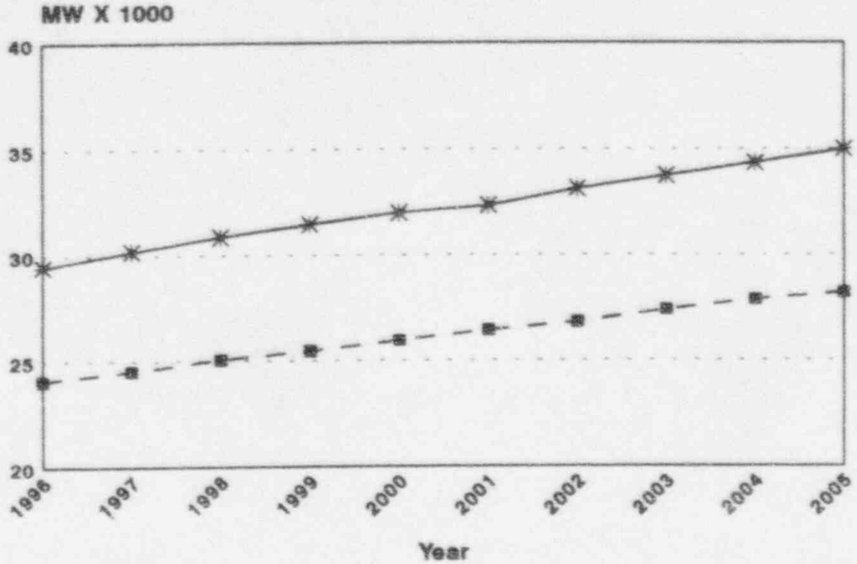


1995 Generation

MAIN WUM

Point Beach 1 & 2
Kewaunee

Peak Demand for 10 Years



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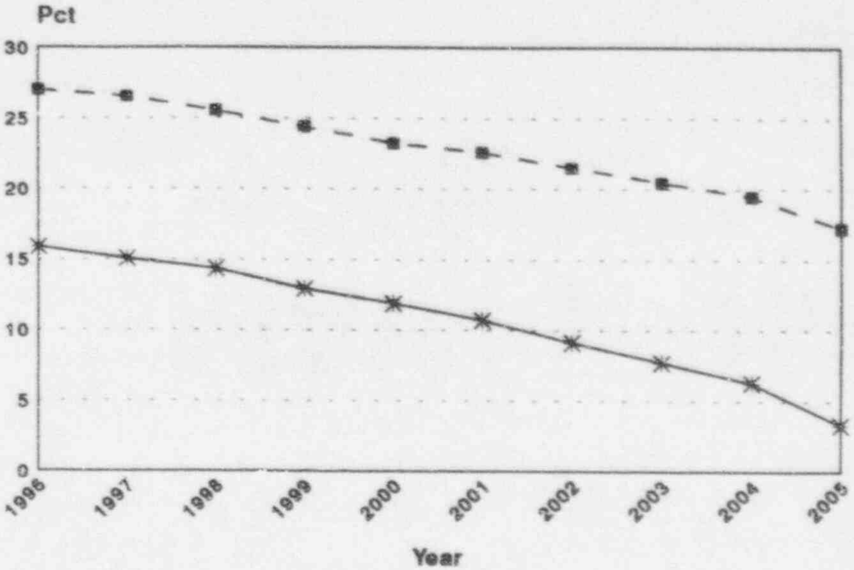

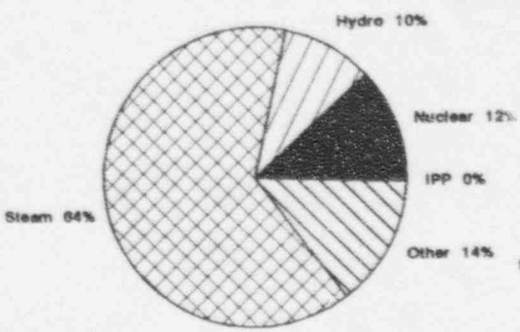

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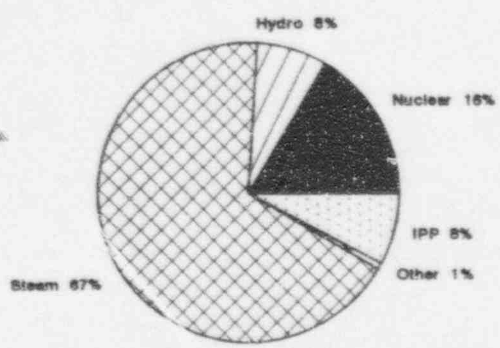
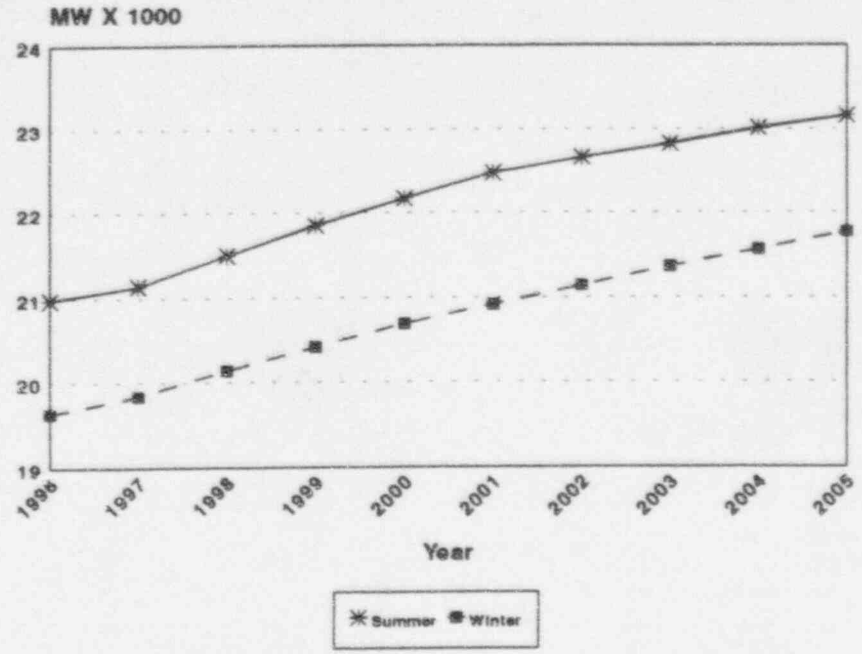


1995 Generation

MAPP

Duane Arnold
Fort Calhoun
Monticello
Prairie Island 1 & 2

Peak Demand for 10 Years



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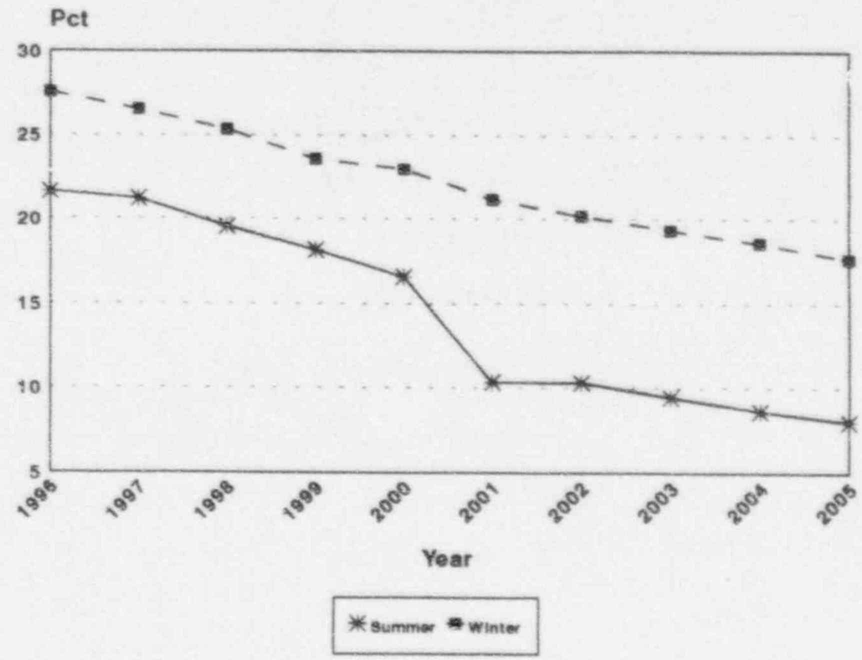

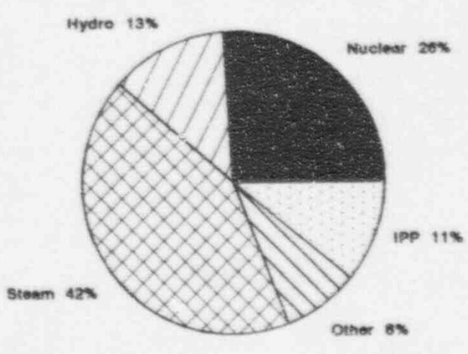

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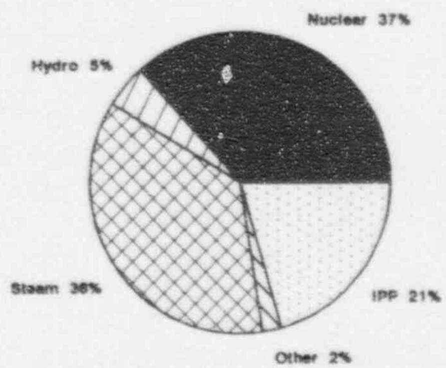
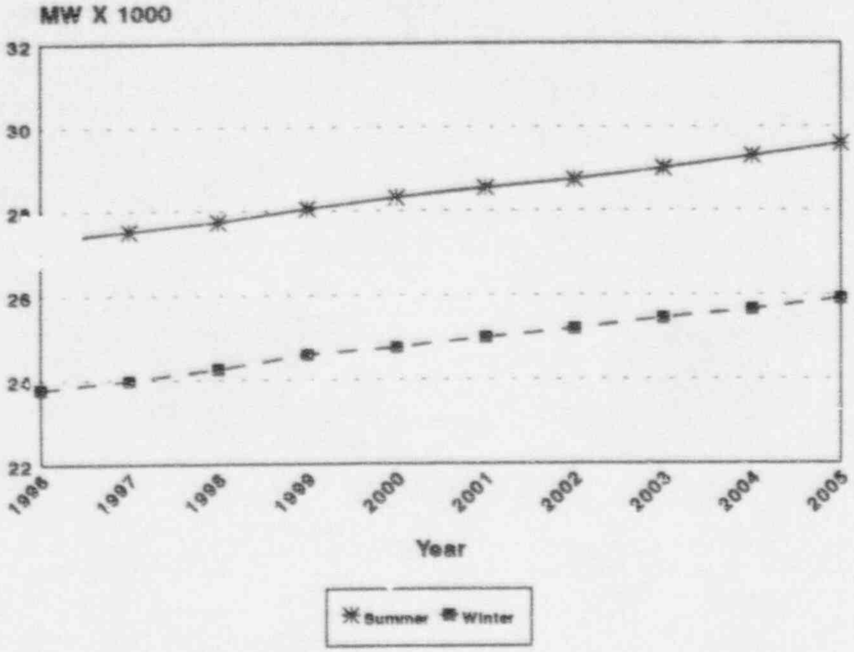


1995 Generation

NPCC NE

Haddam Neck
Maine Yankee
Millstone 1, 2, & 3
Pilgrim
Seabrook
Vermont Yankee

Peak Demand for 10 Years



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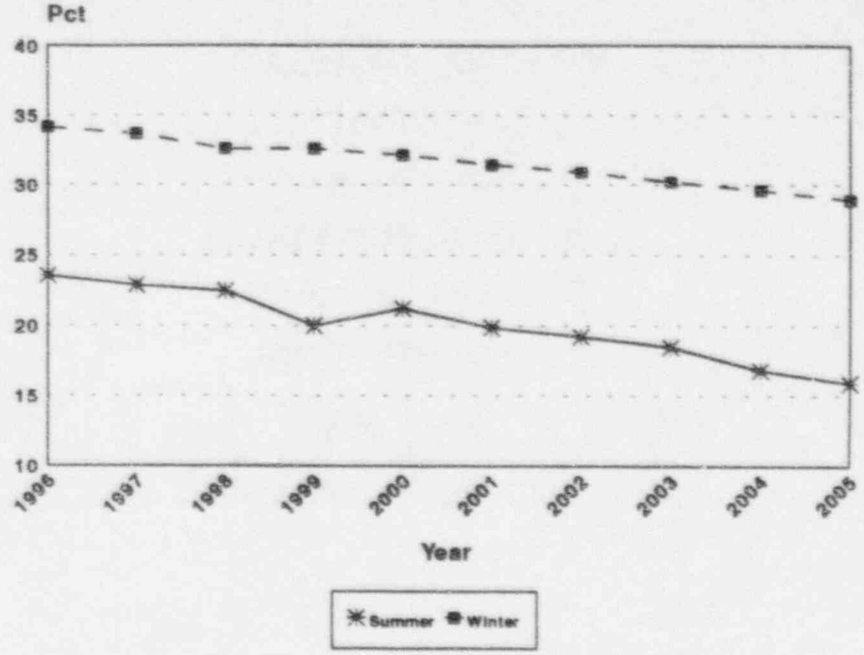

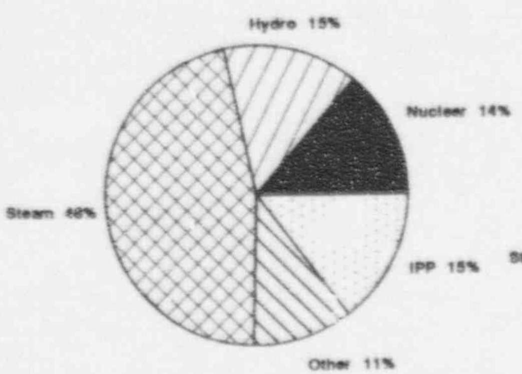

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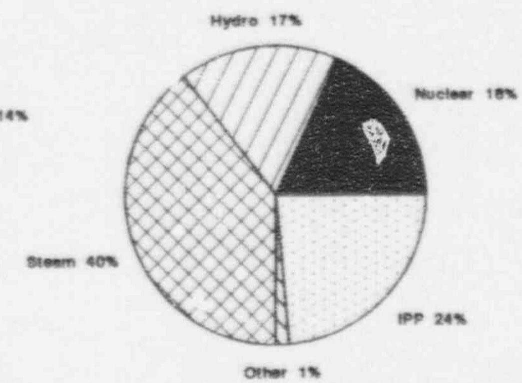
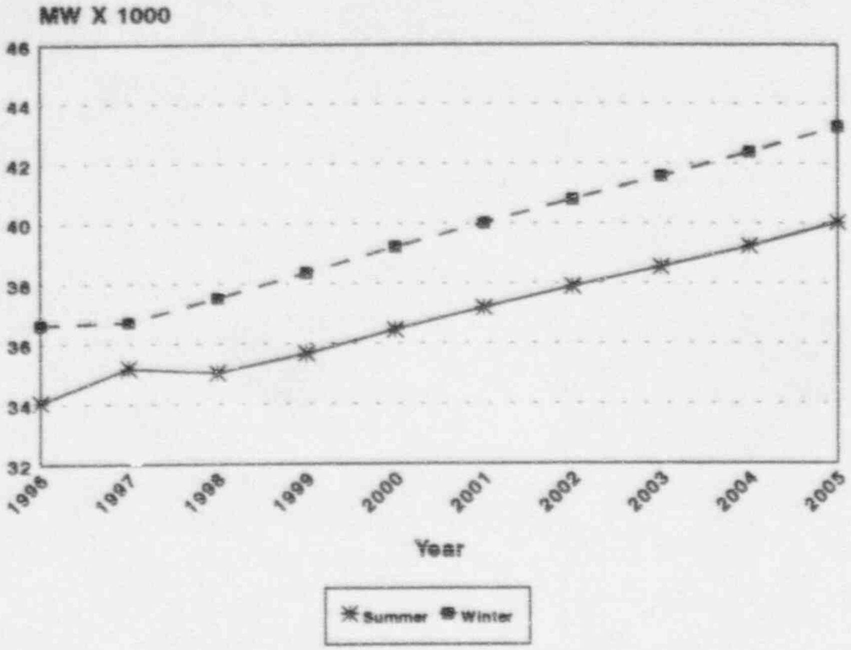


1995 Generation

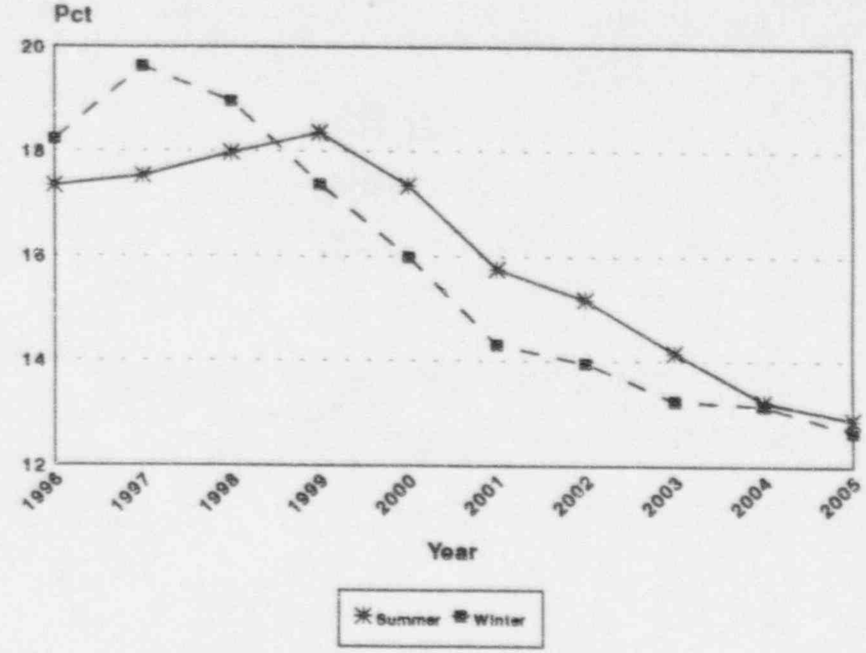
NPCC NY

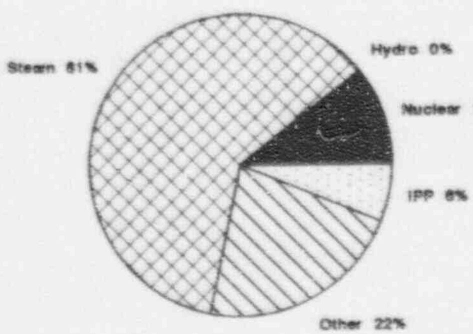
FitzPatrick
Ginna
Indian Point 2 & 3
Nine Mile Point 1 & 2

Peak Demand for 10 Years

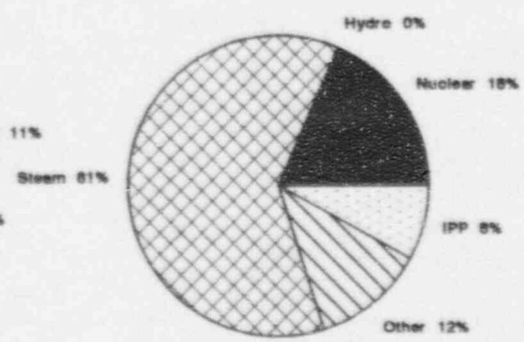


Capacity Margin





1995 Capacity

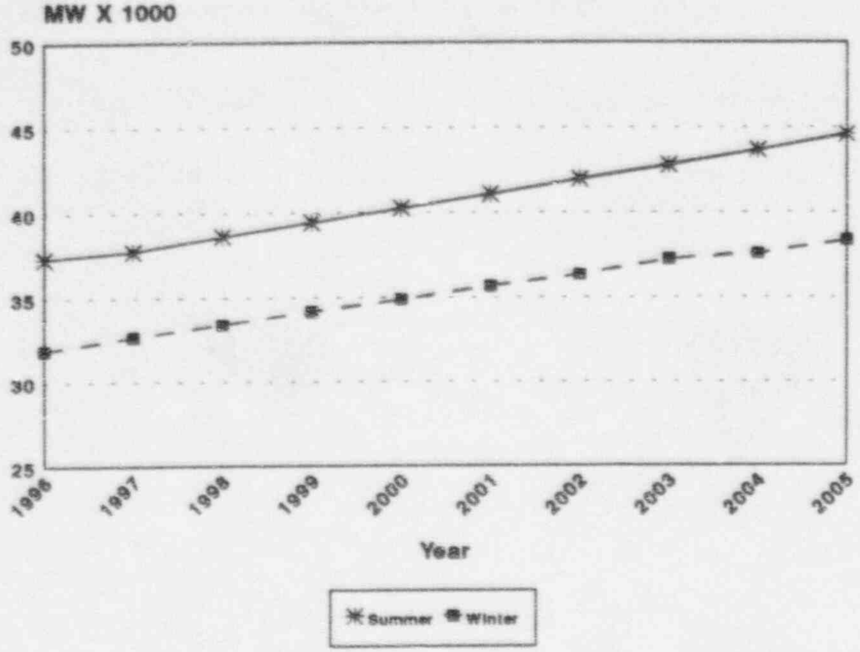


1995 Generation

SERC FLA

Crystal River 3
St. Lucie 1 & 2
Turkey Point 3 & 4

Peak Demand for 10 Years



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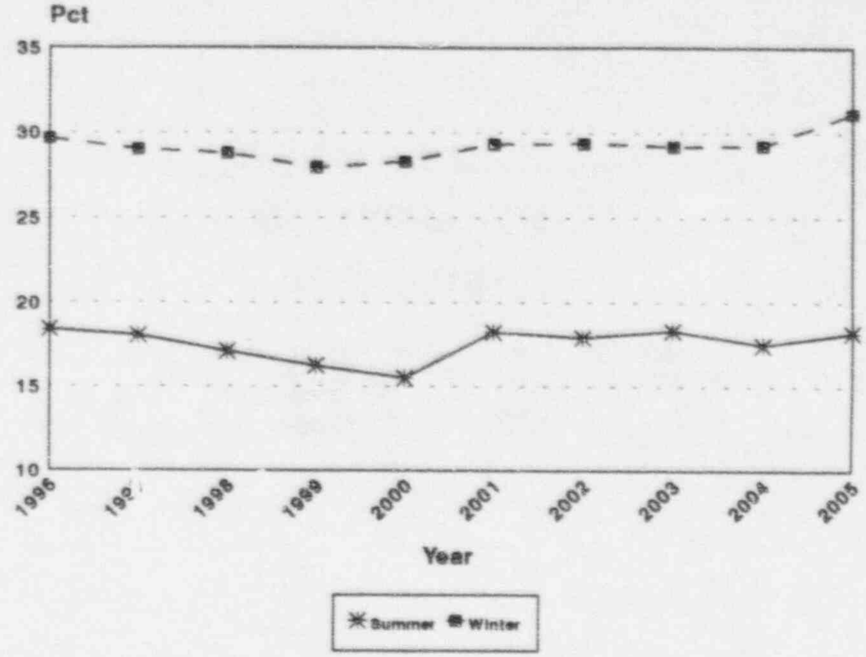

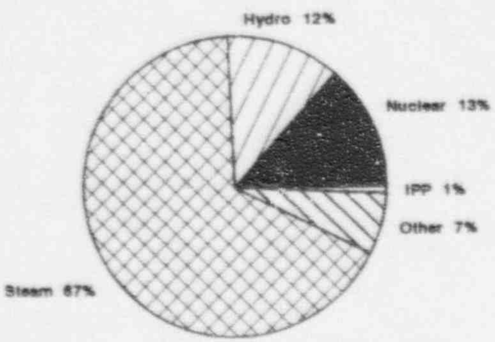

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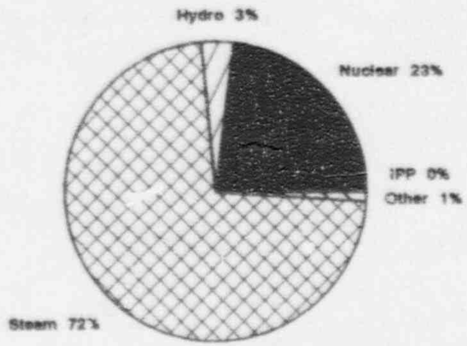
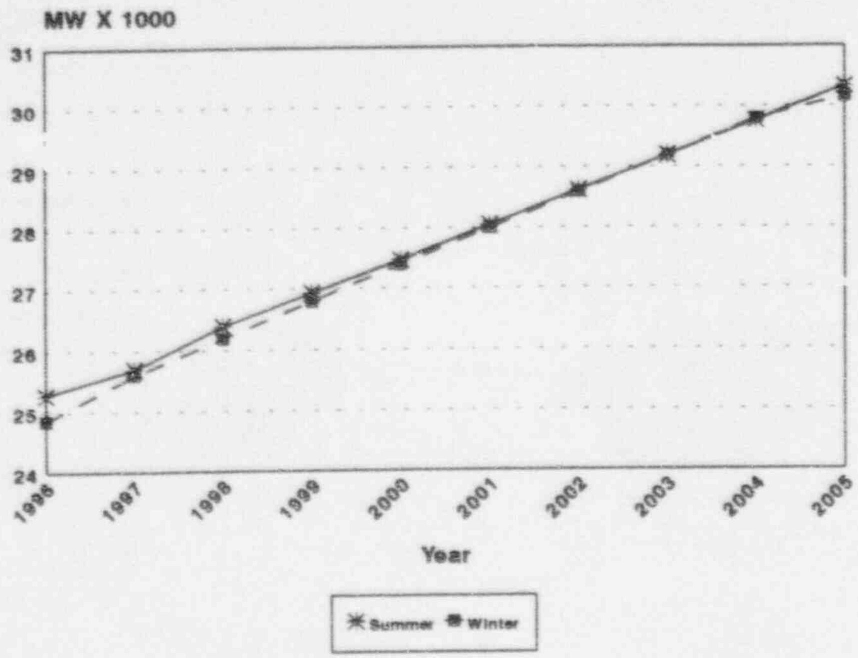


1995 Generation

SERC SOU

Farley 1 & 2
Grand Gulf
Hatch 1 & 2
Vogtle 1 & 2

Peak Demand for 10 Years



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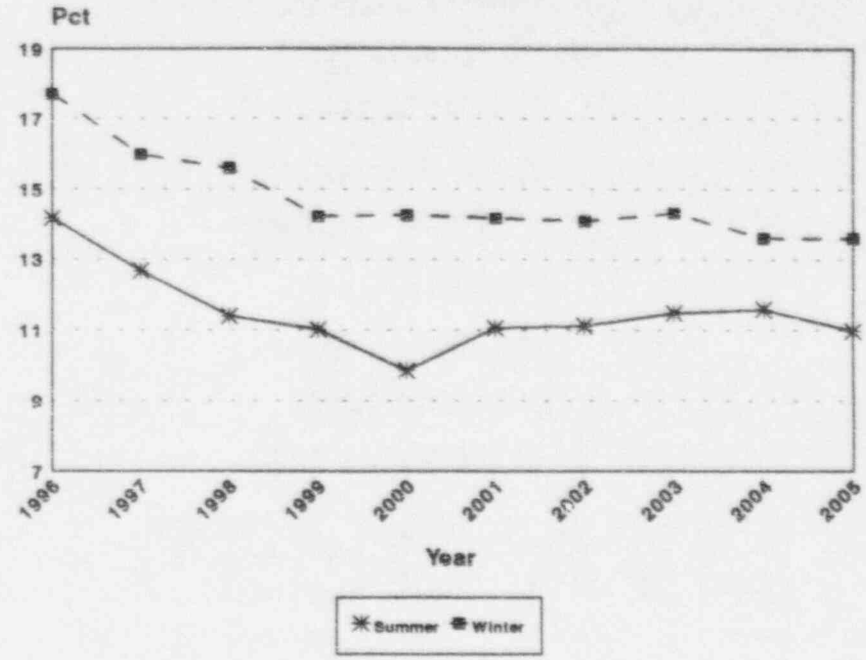

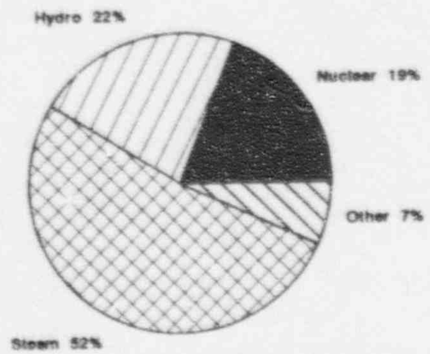

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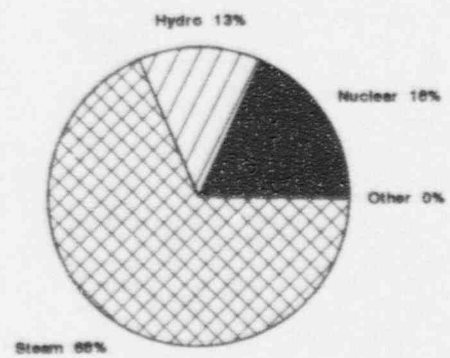
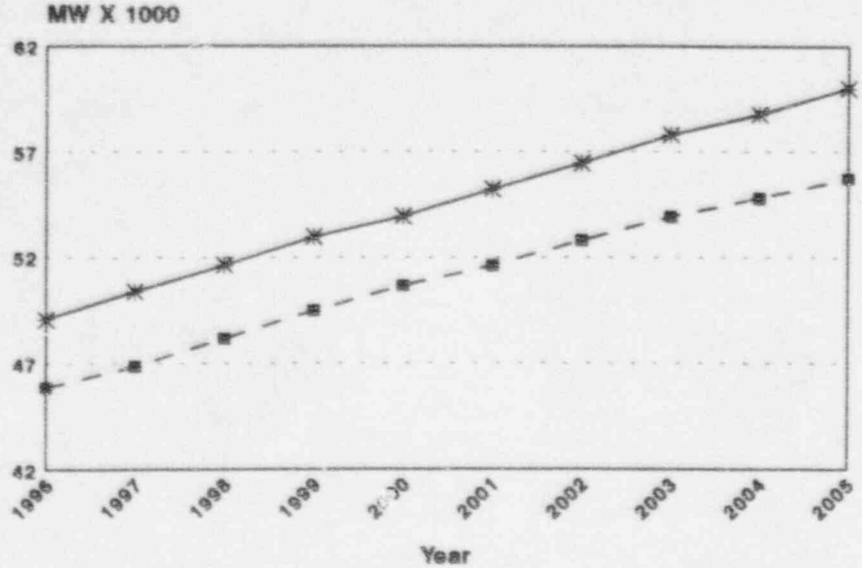


1995 Generation

SERC TVA

Browns Ferry 1, 2, & 3
Sequoyah 1 & 2

Peak Demand for 10 Years



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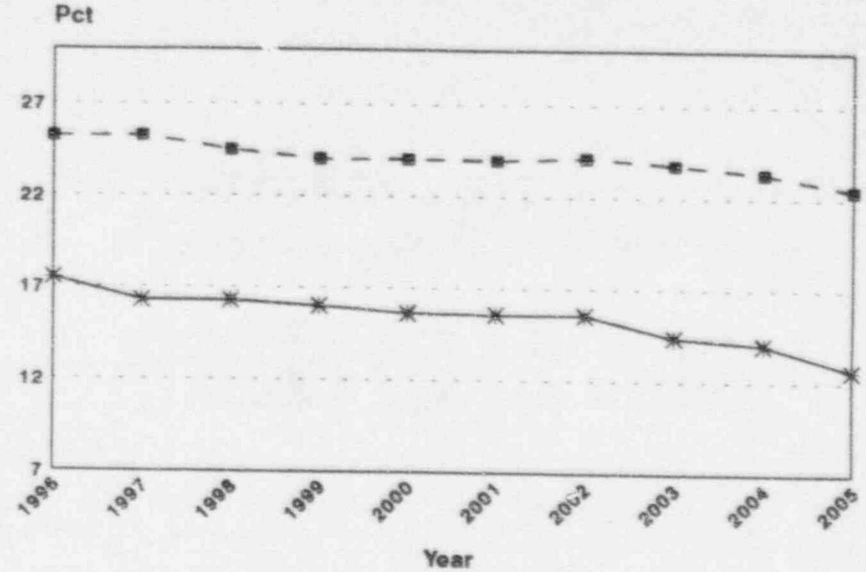

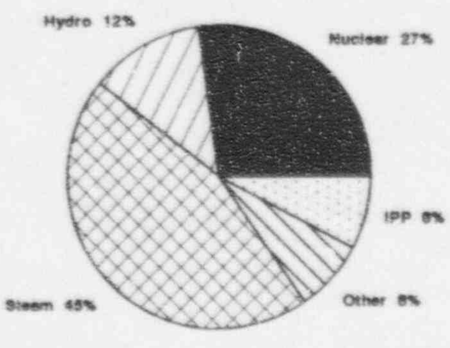

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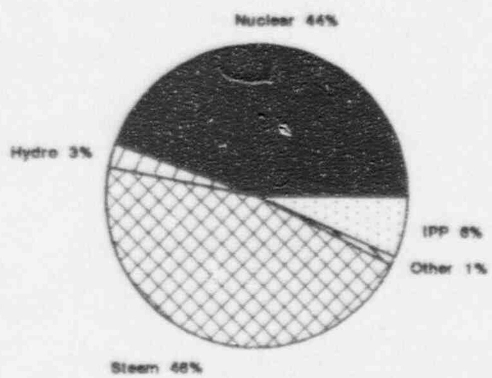
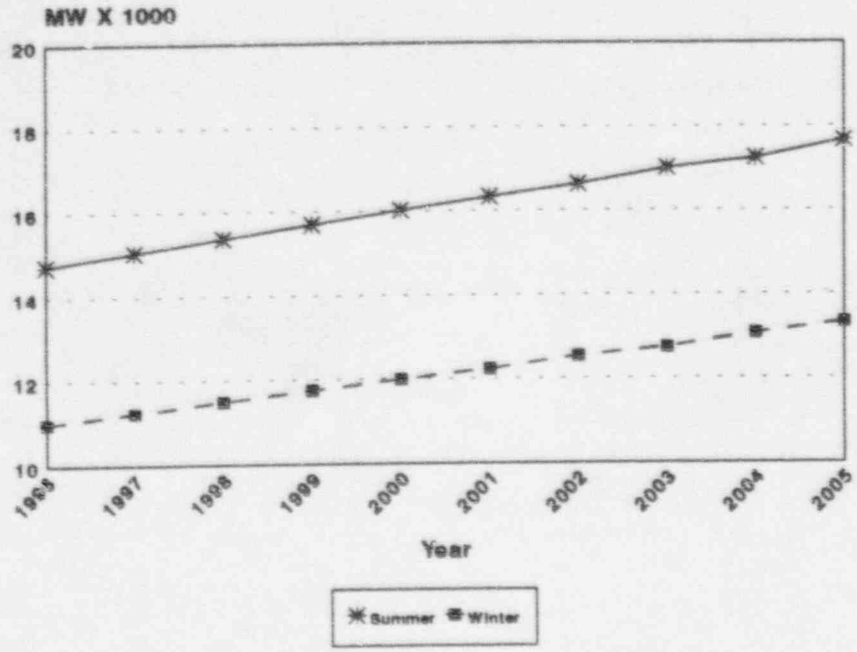


1995 Generation

SERC VAC

Brunswick 1 & 2
Cataba 1 & 2
H. B. Robinson 2
McGuire 1 & 2
North Anna 1 & 2
Oconee 1, 2, & 3
Shearon Harris
Surry 1 & 2
V. C. Summer

Peak Demand for 10 Years



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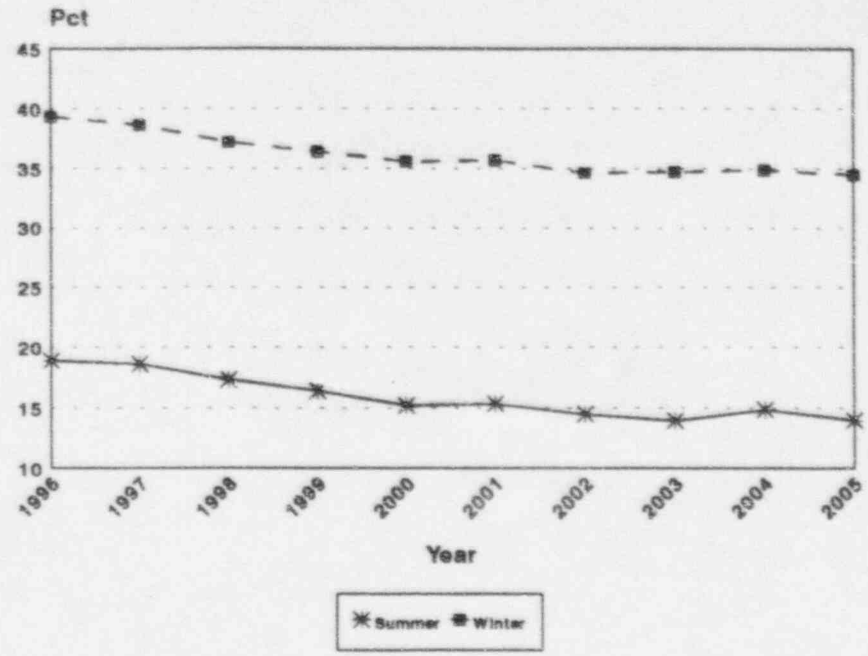

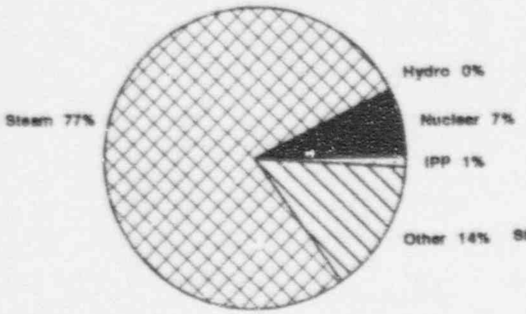

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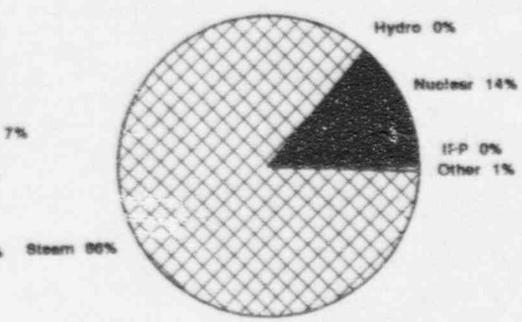
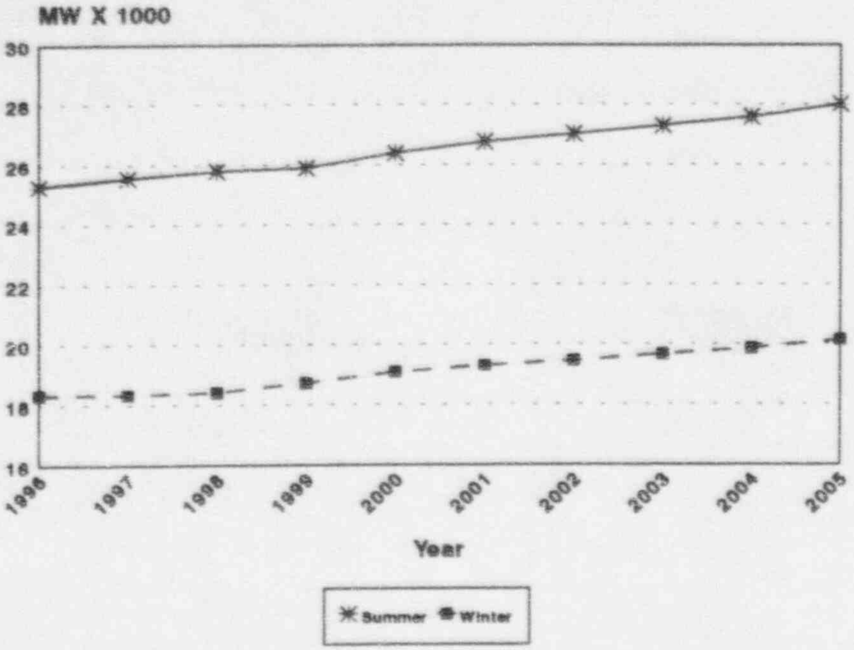


1995 Generation

SPP NOR

Wolf Creek

Peak Demand for 10 Years



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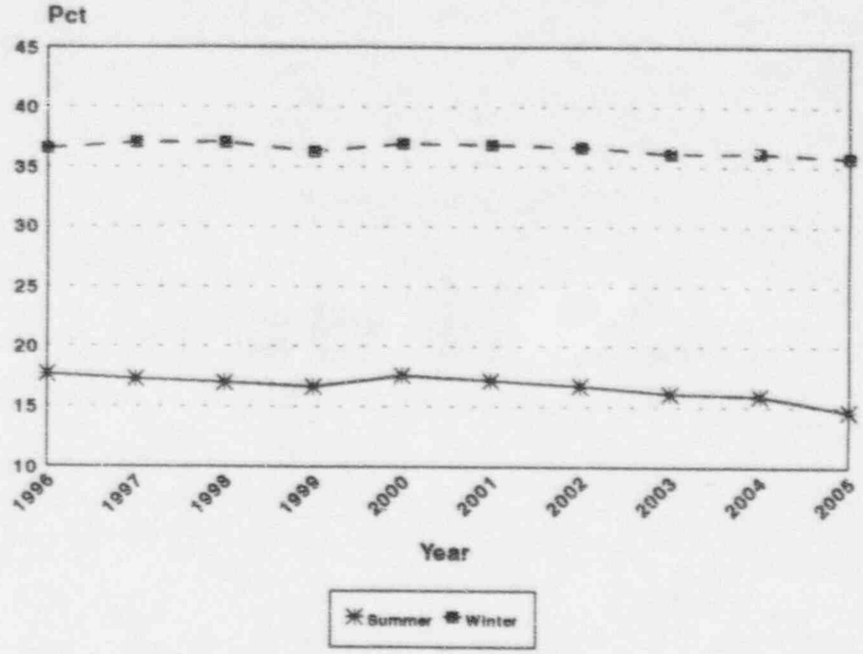

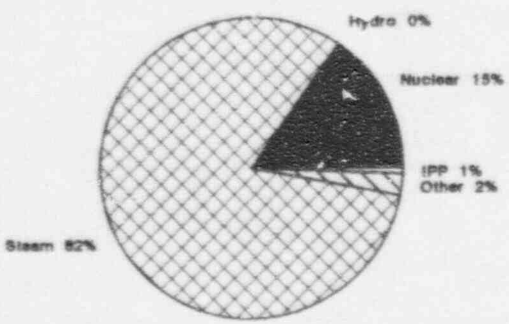

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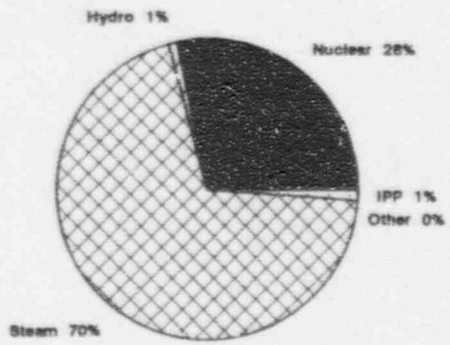
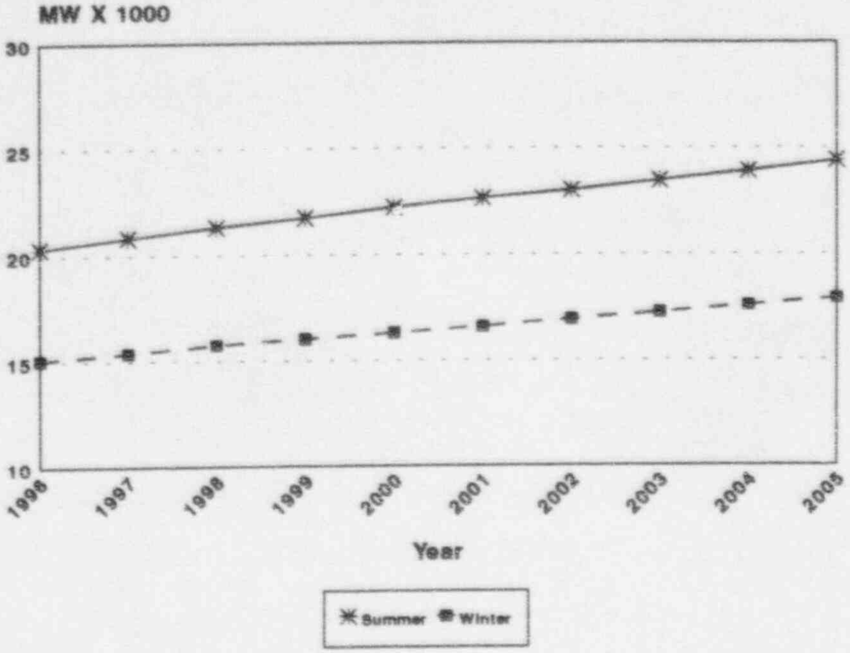


1995 Generation

SPP SE

ANO 1 & 2
Riverbend
Waterford 3

Peak Demand for 10 Years



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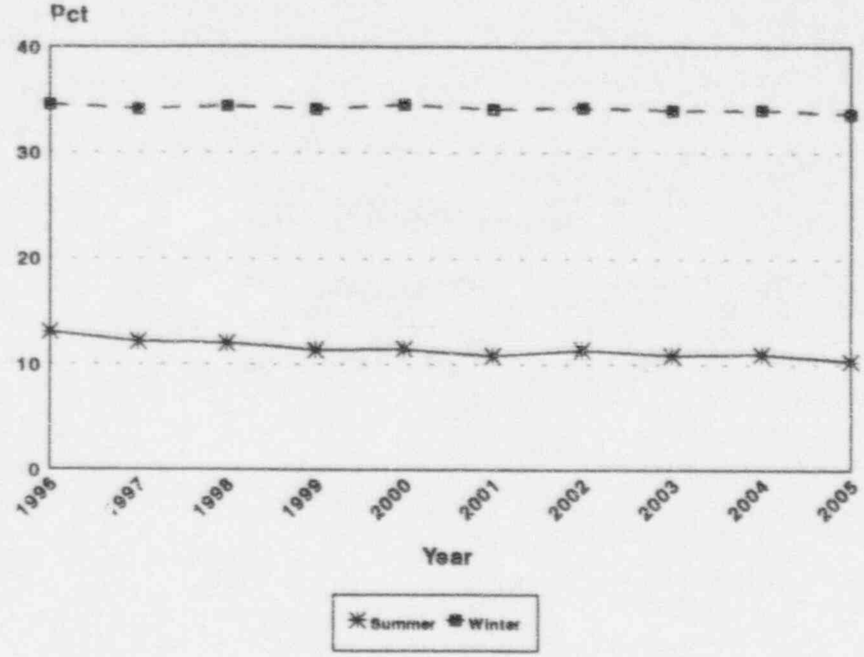

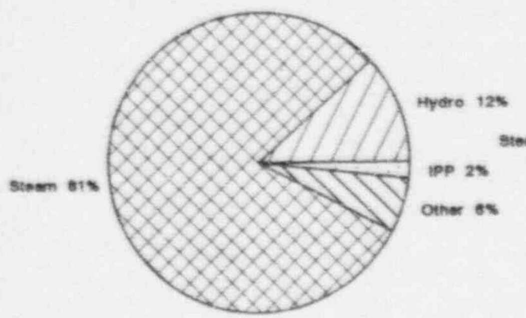

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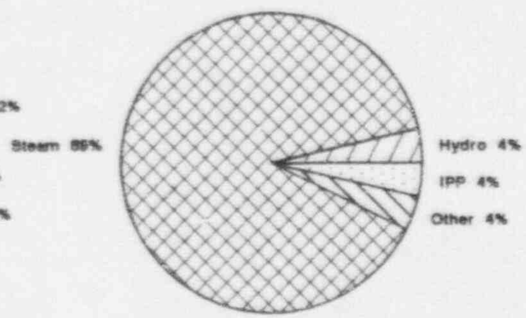
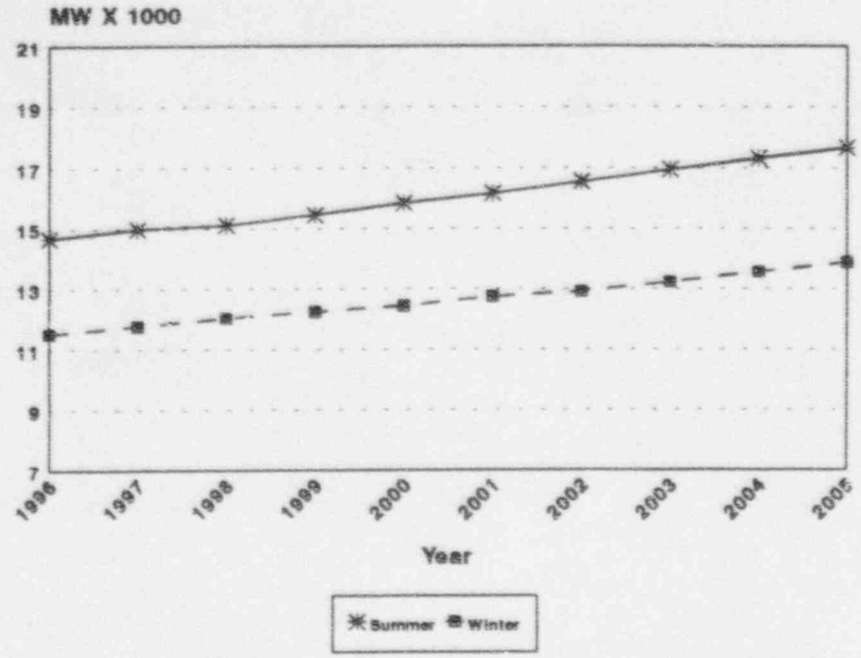


1995 Generation

SPP WCN

Peak Demand for 10 Years



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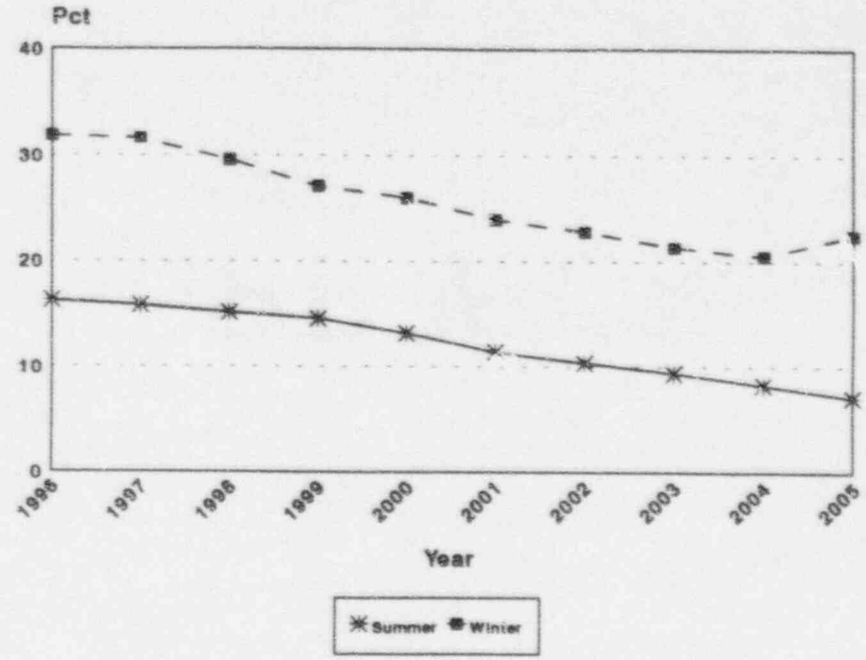

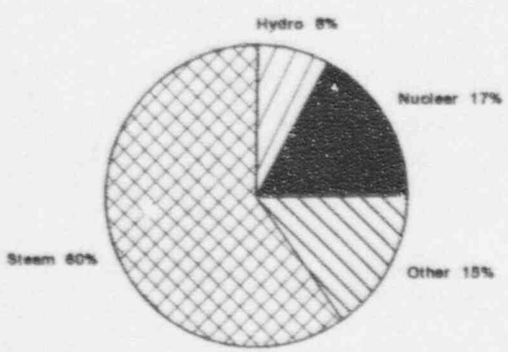

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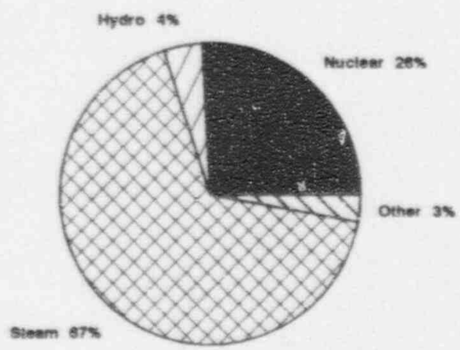
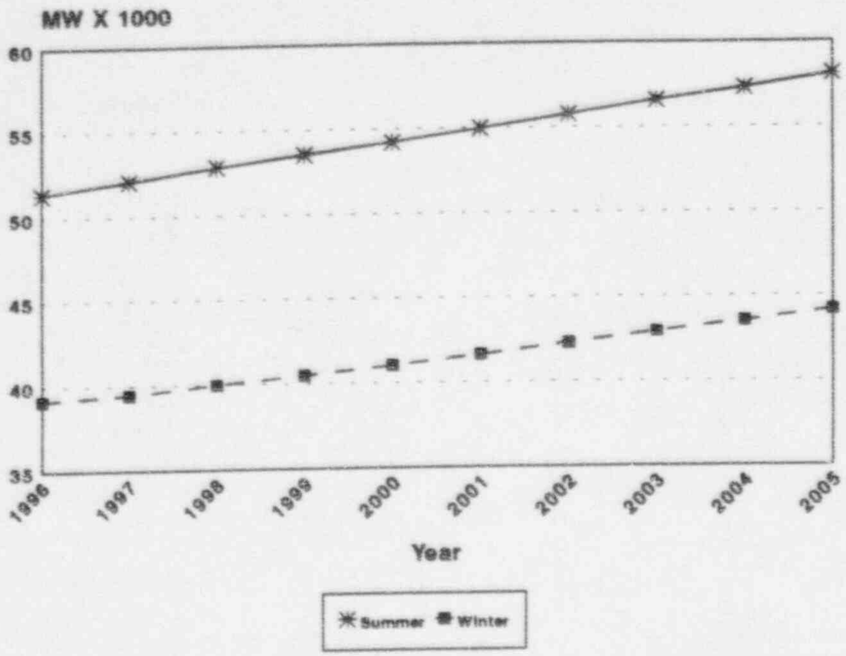


1995 Generation

WSCC AZN

Palo Verde 1, 2, & 3

Peak Demand for 10 Years



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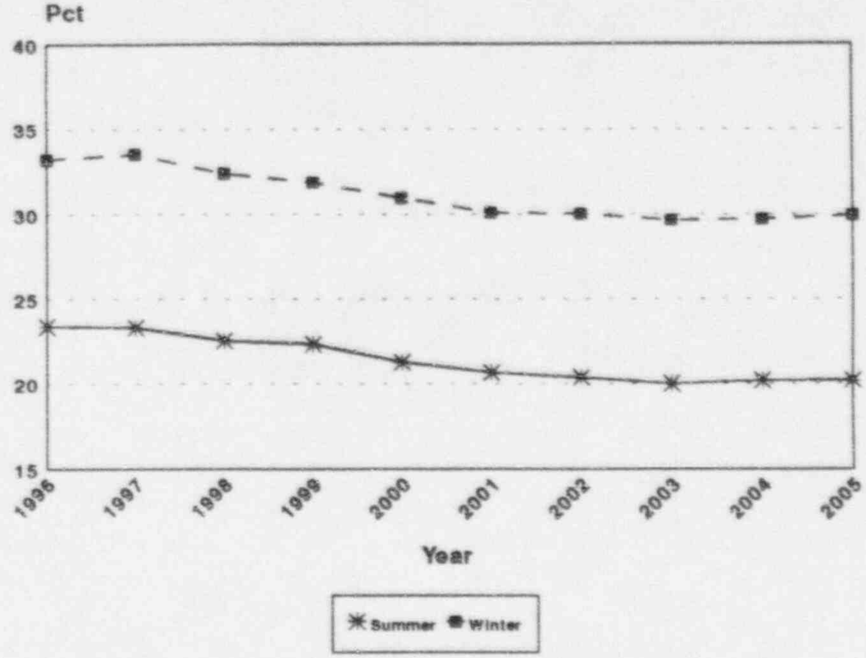

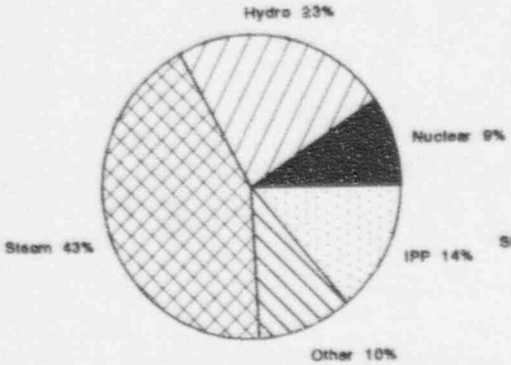

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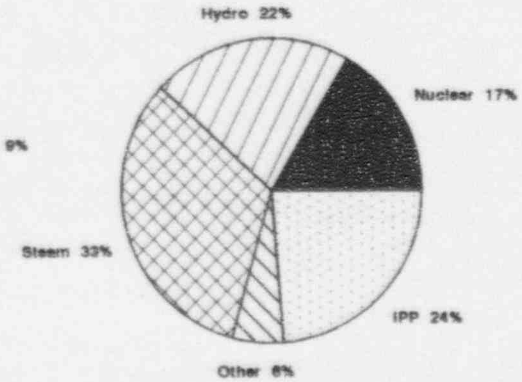
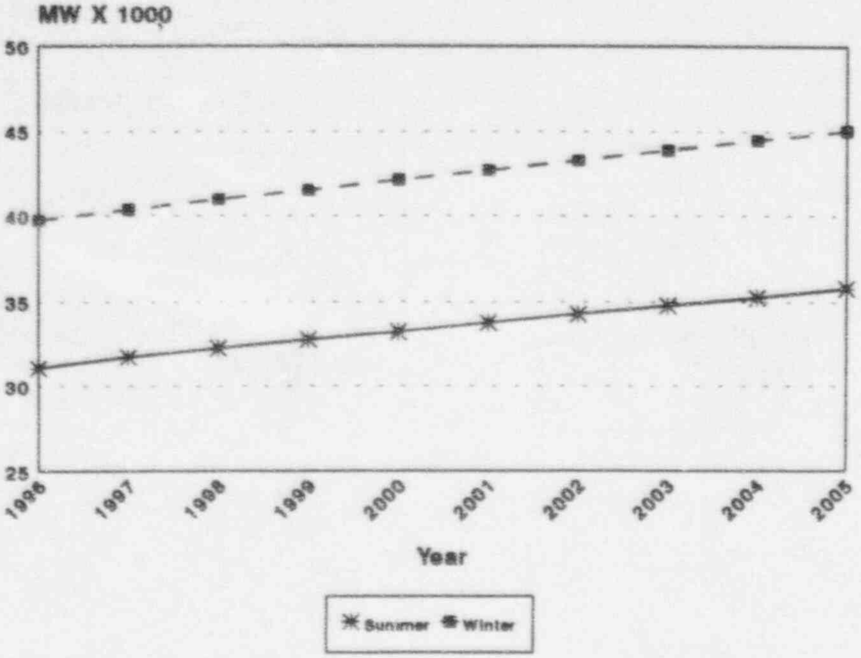


1995 Generation

WSCC CNV

Diablo Canyon 1 & 2
San Onofre 2 & 3

Peak Demand for 10 Years



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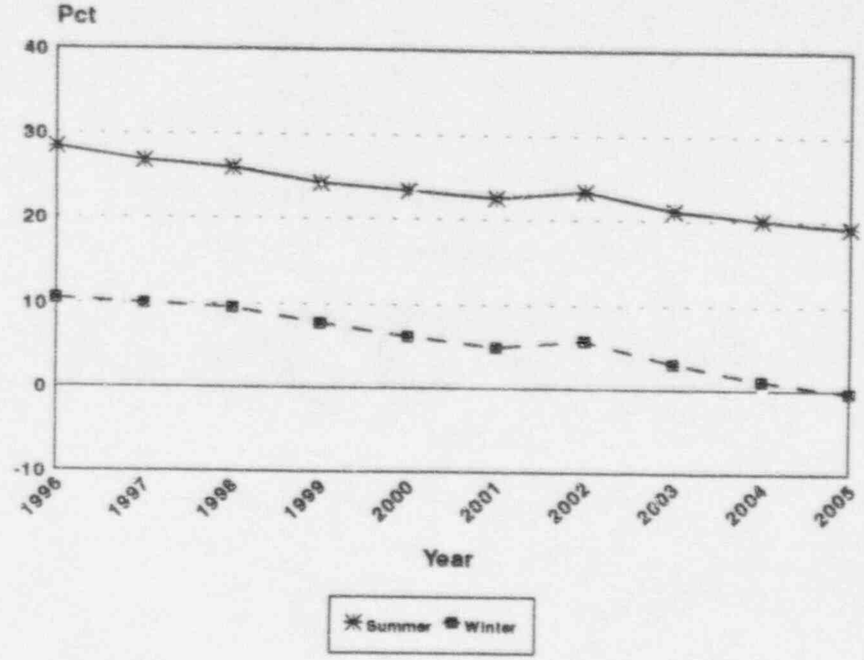

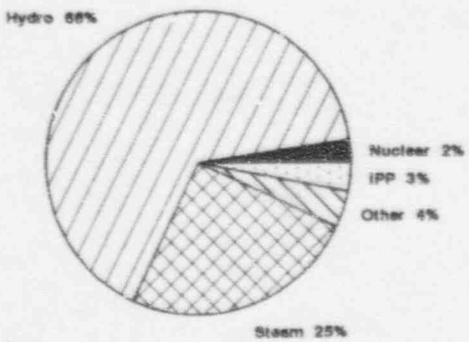

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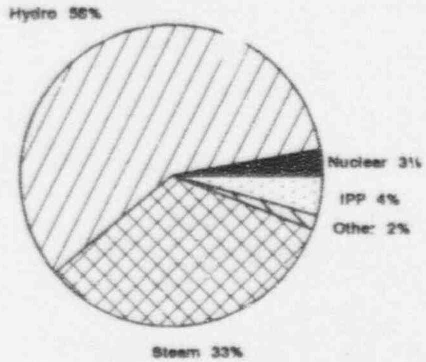
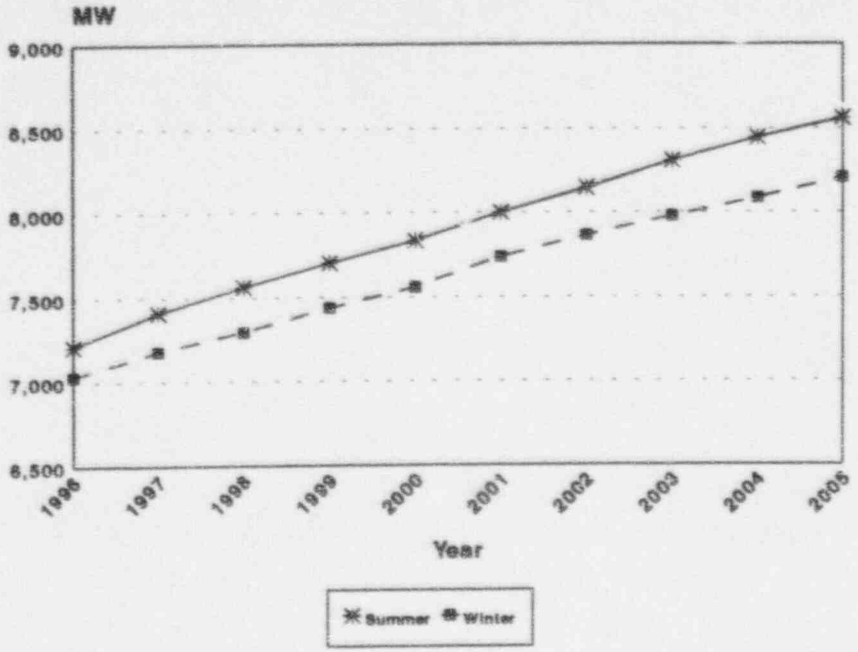


1995 Generation

WSCC NW

WNP 2

Peak Demand for 10 Years



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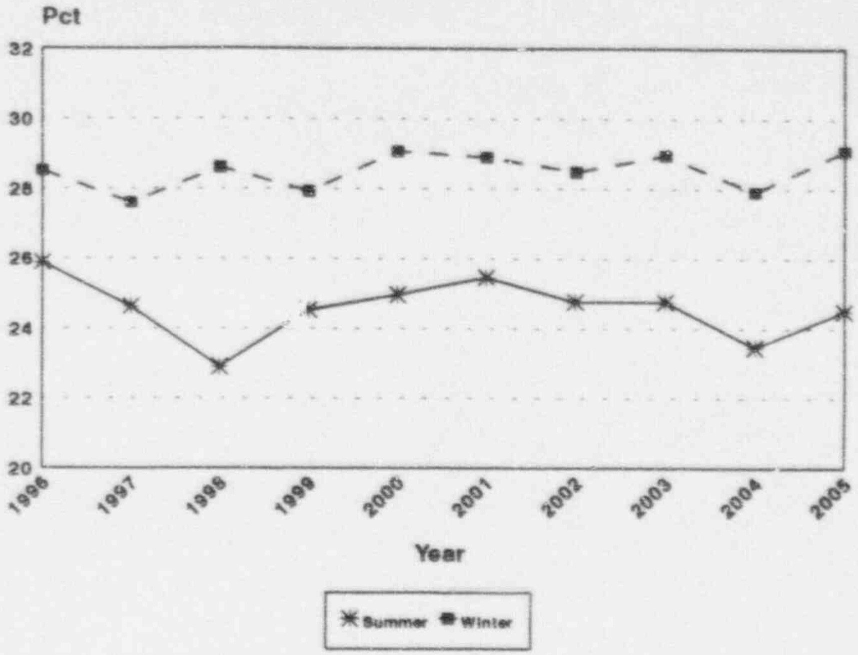

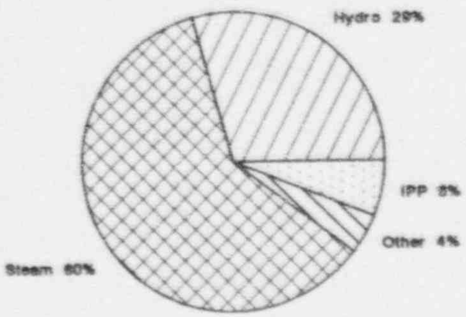

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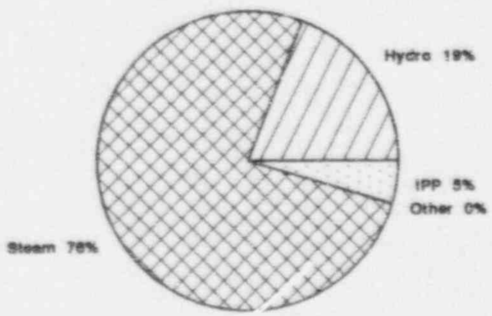
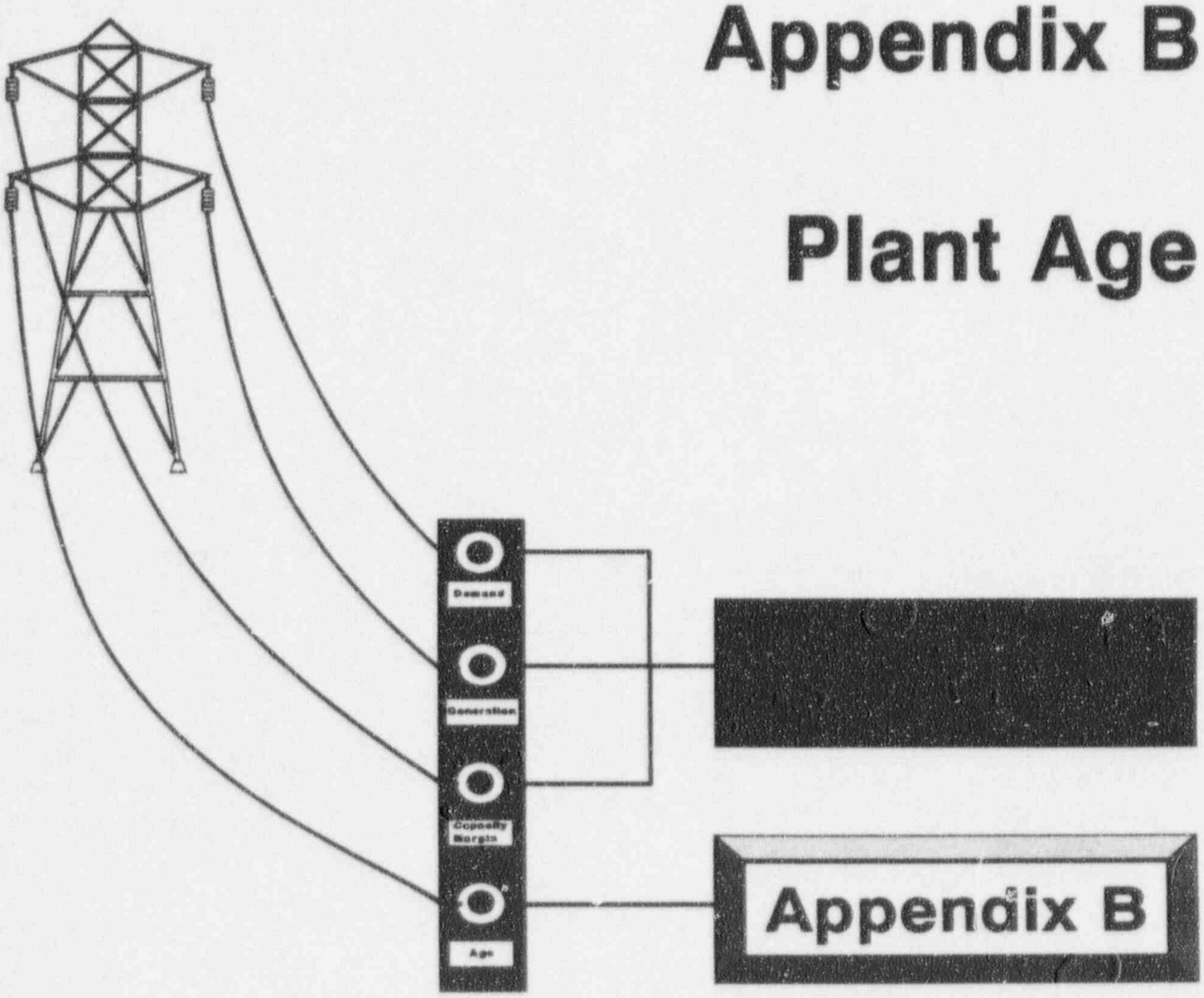


1995 Generation

WSCC RM

Appendix B

Plant Age



PLANT AGE

(Alphabetically by State)

State	Max	Min	Avg	±US Avg
Alabama	70	4	39	1
Arizona	86	3	33	-5
Arkansas	71	2	33	-5
California	102	2	39	1
Colorado	90	2	40	2
Connecticut	92	5	47	9
Delaware	48	2	23	-15
Florida	59	2	25	-13
Georgia	92	3	43	5
Idaho	89	2	50	12
Illinois	70	2	32	-6
Indiana	82	2	31	-7
Iowa	82	2	38	0
Kansas	68	2	31	-7
Kentucky	70	5	37	-1
Louisiana	53	3	29	-9
Maine	92	5	50	12
MD & DC	70	2	30	-8
Massachusetts	91	4	40	2
Michigan	90	2	42	4
Minnesota	89	2	40	2
Mississippi	59	11	35	-3
Missouri	66	2	30	-8
Montana	89	10	58	20
Nebraska	80	2	37	-1
Nevada	91	2	37	-1
N Hampshire	78	5	49	11
New Jersey	65	2	29	-9
New Mexico	68	7	33	-5
New York	97	3	44	6
North Carolina	97	7	47	9
North Dakota	58	10	35	-3
Ohio	72	2	29	-9
Oklahoma	71	4	32	-6
Oregon	89	2	40	2
Pennsylvania	90	6	33	-5
Rhode Island	65	8	29	-9
South Carolina	90	4	46	8
South Dakota	64	4	32	-6
Tennessee	85	9	33	-5
Texas	96	2	31	-7
Utah	99	2	36	-2
Vermont	97	3	54	16
Virginia	92	2	34	-4
Washington	97	2	40	2
West Virginia	86	6	44	6
Wisconsin	95	2	48	10
Wyoming	73	3	34	-4
US	102	2	38	

PLANT AGE

(By Maximum Age)

State	Max	Min	Avg	±US Avg
US	102	2	38	
California	102	2	39	1
Utah	99	2	36	-2
Washington	97	2	40	2
Vermont	97	3	54	16
New York	97	3	44	6
North Carolina	97	7	47	9
Texas	96	2	31	-7
Wisconsin	95	2	48	10
Connecticut	92	5	47	9
Maine	92	5	50	12
Georgia	92	3	43	5
Virginia	92	2	34	-4
Massachusetts	91	4	40	2
Nevada	91	2	37	-1
South Carolina	90	4	46	8
Pennsylvania	90	6	33	-5
Michigan	90	2	42	4
Colorado	90	2	40	2
Oregon	89	2	40	2
Idaho	89	2	50	12
Minnesota	89	2	40	2
Montana	89	10	58	20
West Virginia	86	6	44	6
Arizona	86	3	33	-5
Tennessee	85	9	33	-5
Iowa	82	2	38	0
Indiana	82	2	31	-7
Nebraska	80	2	37	-1
N Hampshire	78	5	49	11
Wyoming	73	3	34	-4
Ohio	72	2	29	-9
Arkansas	71	2	33	-5
Oklahoma	71	4	32	-6
Illinois	70	2	32	-6
MD & DC	70	2	30	-8
Alabama	70	4	39	1
Kentucky	70	5	37	-1
Kansas	68	2	31	-7
New Mexico	68	7	33	-5
Missouri	66	2	30	-8
New Jersey	65	2	29	-9
Rhode Island	65	8	29	-9
South Dakota	64	4	32	-6
Mississippi	59	11	35	-3
Florida	59	2	25	-13
North Dakota	58	10	35	-3
Louisiana	53	3	29	-9
Delaware	48	2	23	-15

PLANT AGE

(By Average Age)

State	Max	Min	Avg	±US Avg
Montana	89	10	58	20
Vermont	97	3	54	16
Idaho	89	2	50	12
Maine	92	5	50	12
N Hampshire	78	5	49	11
Wisconsin	95	2	48	10
North Carolina	97	7	47	9
Connecticut	92	5	47	9
South Carolina	90	4	46	8
New York	97	3	44	6
West Virginia	86	6	44	6
Georgia	92	3	43	5
Michigan	90	2	42	4
Minnesota	89	2	40	2
Oregon	89	2	40	2
Massachusetts	91	4	40	2
Washington	97	2	40	2
Colorado	90	2	40	2
California	102	2	39	1
Alabama	70	4	39	1
US	102	2	38	
Iowa	82	2	38	0
Nebraska	80	2	37	-1
Nevada	91	2	37	-1
Kentucky	70	5	37	-1
Utah	99	2	36	-2
Mississippi	59	11	35	-3
North Dakota	58	10	35	-3
Wyoming	73	3	34	-4
Virginia	92	2	34	-4
New Mexico	68	7	33	-5
Arizona	86	3	33	-5
Arkansas	71	2	33	-5
Pennsylvania	90	6	33	-5
Tennessee	85	9	33	-5
South Dakota	64	4	32	-6
Oklahoma	71	4	32	-6
Illinois	70	2	32	-6
Texas	96	2	31	-7
Indiana	82	2	31	-7
Kansas	68	2	31	-7
Missouri	66	2	30	-8
MD & DC	70	2	30	-8
Rhode Island	65	8	29	-9
New Jersey	65	2	29	-9
Ohio	72	2	29	-9
Louisiana	53	3	29	-9
Florida	59	2	25	-13
Delaware	48	2	23	-15