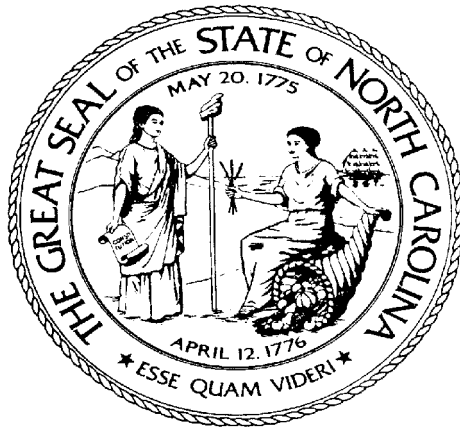


ANNUAL REPORT

of the

**NORTH CAROLINA
UTILITIES COMMISSION**



Regarding

Long Range Needs for Expansion of

Electric Generation Facilities

for Service in North Carolina

- June 2001 -

June 19, 2001

The Honorable Michael F. Easley
Governor
State of North Carolina
Capitol Building
Raleigh, North Carolina 27611

Dear Governor Easley:

The North Carolina Utilities Commission hereby presents for your consideration the North Carolina Utilities Commission's Annual Report on the Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina. This report is made to you and to the members of the Joint Legislative Utility Review Committee of the General Assembly pursuant to G.S. 62-110.1(c).

The report is an update of the Commission's Report of July 2000 and is based on the most current reports (as of April 30, 2001) of the electric utilities serving North Carolina and on the Commission's Order of April 4, 2001, in Docket No. E-100, Sub 88.

Very truly yours,

Jo Anne Sanford, Chair

JAS/DFC/jme

Copies of the Annual Report of the North Carolina Utilities Commission Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina have been mailed to the following:

The Honorable Beverly Perdue
Office of the Lieutenant Governor
310 N. Blount Street
Raleigh, North Carolina 27603

The Honorable Marc Basnight
President Pro Tem of the Senate
North Carolina General Assembly
2007 State Legislative Building
Raleigh, North Carolina 27601-2808

The Honorable James B. Black
Speaker of the House of Representatives
North Carolina General Assembly
2304 State Legislative Building
Raleigh, North Carolina 27601-1096

The Honorable David W. Hoyle
North Carolina General Assembly
Co-Chair of Joint Legislative Utility Review Committee
300-A Legislative Office Building
Raleigh, North Carolina 27601-2808

The Honorable John A. Garwood
North Carolina General Assembly
Joint Legislative Utility Review Committee
1118 State Legislative Building
Raleigh, NC 27601-2808

The Honorable Howard N. Lee
North Carolina General Assembly
Joint Legislative Utility Review Committee
629 Legislative Office Building
Raleigh, NC 27601-2808

The Honorable R. L. Martin
North Carolina General Assembly
Joint Legislative Utility Review Committee
410 Legislative Office Building
Raleigh, North Carolina 27601-2808

The Honorable R. C. Soles, Jr.
North Carolina General Assembly
Joint Legislative Utility Review Committee
2022 State Legislative Building
Raleigh, North Carolina 27601-2808

The Honorable Ronald L. Smith
North Carolina General Assembly
Co-Chair, Joint Legislative Utility Review Committee
2223 State Legislative Building
Raleigh, North Carolina 27601-1096

The Honorable Zeno L. Edwards
North Carolina General Assembly
Joint Legislative Utility Review Committee
637 Legislative Office Building
Raleigh, North Carolina 27601-1096

The Honorable George M. Holmes
North Carolina General Assembly
Joint Legislative Utility Review Committee
2119 State Legislative Building
Raleigh, North Carolina 27601-1096

The Honorable Drew P. Saunders
North Carolina General Assembly
Joint Legislative Utility Review Committee
1217 State Legislative Building
Raleigh, North Carolina 27601-1096

Mr. Steven J. Rose
Committee Counsel
Joint Legislative Utility Review Committee
545 Legislative Office Building
Raleigh, North Carolina 27601-2808

Mrs. Esther Manheimer
Assistant Committee Counsel
Joint Legislative Utility Review Committee
545 Legislative Office Building
Raleigh, North Carolina 27601-2808

Mrs. Penny N. Williams
Committee Clerk
Joint Legislative Utility Review Committee
300 Legislative Office Building
Raleigh, North Carolina 27601-2808

Mr. Robert P. Gruber
Executive Director
North Carolina Utilities Commission - Public Staff
4326 Mail Service Center
Raleigh, North Carolina 27699-4326

Ms. Margaret A. Force
Assistant Attorney General
North Carolina Department of Justice - Consumer Protection/Utilities
Old Education Building, Second Floor
Raleigh, North Carolina 27602

Mr. Larry E. Shirley
Director, Energy Division
North Carolina Department of Commerce
1340 Mail Service Center
Raleigh, North Carolina 27699-1340

Carolina Power & Light Company
Post Office Box 1551
Raleigh, North Carolina 27602-1551
Attention: Mr. William Cavanaugh III
President & CEO

Duke Power, A Duke Energy Company
422 South Church Street
Post Office Box 1244
Charlotte, North Carolina 28201-1244
Attention: Mr. William A. Coley
President

New River Light and Power Company
Post Office Box 1130
Boone, North Carolina 28607
Attention: Mr. Donald R. Austin
General Manager

Dominion North Carolina Power
Post Office Box 26666
Richmond, Virginia 23261-6666
Attention: Mr. Robert E. Rigsby
President and COO

Western Carolina University
Cullowhee, North Carolina 28723-9646

North Carolina Electric Membership Corporation
Post Office Box 27306
Raleigh, North Carolina 27611-7306

ElectriCities of North Carolina
Post Office Box 29513
Raleigh, North Carolina 27626-0513

TABLE OF CONTENTS

Executive Summary.	1
Introduction.	4
Overview of the Electric Utility Industry in North Carolina.	5
Historical Peak Demand.	7
Load Forecasts.	9
Demand Side Resources.	11
Supply Side Resources.	11
Reserve Margins.	14
Reliability.	15
North Carolina Electric Membership Corporation.	16
Integrated Resource Planning.	17
Electric Industry Restructuring.	19
Summary.	22
Appendices - please contact the Chief Clerk's Office for the appendices.	

EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to G.S. 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, and a report on its plan for meeting those needs. The information contained in this report is based primarily on the most current reports (as of May 1, 2001) to the Commission by the electric utilities regarding their respective analyses and plans for meeting the demand for electricity in their respective service areas. It also reflects the most recent hearings and formal proceedings held in early 2001 to review the plans and analyses of the utilities, as well as other records and files of the Commission.

The two largest investor-owned utilities (IOUs) in North Carolina, Duke Power, A Duke Energy Company (Duke) and Carolina Power & Light Company (CP&L), together operate generating units that supply approximately 95% of the electricity consumed in the state. Approximately 20% of the IOUs' total electric sales in North Carolina are to the wholesale market in North Carolina, consisting primarily of electric membership cooperatives and municipally-owned electric systems. Forecasts of the future electric power needs of the wholesale market are incorporated into the overall forecasts of the regulated IOUs. Two of the regulated utilities are university-owned and are included in the wholesale market planning of the IOUs. Table 1 below illustrates the electricity sales of the regulated utilities in North Carolina.

Table 1: Electricity Sales of Regulated Utilities In North Carolina - 2000

	NC Retail GWh*	NC Wholesale GWh*	Total GWh Sales* (NC Plus Other States)
CP&L	34,746.9	13,867.6	56,652.8
Duke	52,659.9	6,648.8	84,634.2
NC Power	3,358.9	1,708.6	76,155.4
New River	212.8	0	212.8
Western Carolina (1)	25.0	0	25.0

*GWh = 1 Million kWh

(1) Figures for Western Carolina University are estimated from its annual calculations for fuel charge adjustments.

North Carolina is considered a strong growth state. The average annual growth rate in summer peak demand for electricity was approximately 3% for the 1980-2000 period. The annual summer peak demand remains predominant over winter peak demand for integrated resource planning purposes.

The major IOUs in North Carolina each utilize generally accepted forecasting procedures. Although their respective forecasting models are different, the econometric techniques employed by

each utility are widely used for projecting future trends. Table 5 below illustrates the systemwide average annual rates of growth which are currently forecast by the major IOUs in North Carolina.

Table 5: Forecast Rates of Growth in Energy and Peak Load for CP&L, Duke, and NC Power

	CP&L (2000-2010)		Duke (2000-2010)		NC Power (2000-2010)	
Summer Peak	307 MW	2.4%	400 MW	2.1%	141 MW	0.8%
Winter Peak	333 MW	2.5%	225 MW	1.4%	87 MW	0.6%
Energy	1,861 MWh	2.8%	2,197 MWh	2.1%	1,045 MWh	1.2%

The major electric utilities serving North Carolina continue to forecast annual rates of load growth that will be generally lower than they have experienced over the past 20 years. Their forecasts are relatively typical for electric utilities serving the southeastern states.

The major North Carolina utilities will also continue to depend on coal-fired and nuclear-fueled steam generation to produce the bulk of their kWh electric output, as illustrated in Table 9 below. It should be noted that the utility purchases listed below include buyback transactions associated with jointly owned plants.

Table 9: Total Energy Resources for CP&L, Duke, and NC Power (2000)

	CP&L	Duke	NC Power
Fossil Steam	50.1%	41.5%	46.6%
Nuclear Steam	39.6%	53.9%	36.8%
Hydroelectric	0.7%	0.1%	4.4%
Combustion Turbines	1.4%	0.4%	6.0%
Utility Purchases	5.6%	2.8%	1.8%
Non-Utility Purchases	2.6%	1.3%	4.4%

The major North Carolina IOUs are projecting reserve margins that will be generally in the range that is typical for electric utilities serving the southeastern states but will be generally lower than the North Carolina utilities have maintained in the past. It should be noted that each of the utilities bases its projected reserve margins on undesignated resources in some fashion. For example, CP&L includes over 3,000 MW of undesignated generating capacity additions for the planning period, and Duke likewise includes over 5,000 MW of such undesignated generating capacity additions.

The current reliability assessments by the North American Electric Reliability Council (NERC) project that the Southeastern Electric Reliability Council (SERC) region will have adequate reserve margins over the next ten years, but point out that much of its projection is based on planned capacity additions that are uncommitted, undefined resources. This indicates that utilities are planning to acquire new capacity with significantly shorter lead times, an approach typically associated with combustion turbine peaking plants. The increasing dependence on uncommitted resources is also representative of the approach being taken by the North Carolina utilities.

The Integrated Resource Planning (IRP) review process has been revised to better accommodate the restructuring of the electric utility industry that has resulted from actions by the Federal Energy Regulatory Commission (FERC). On April 29, 1998, the Commission issued its Order Adopting Revised Rules in Docket No. E-100, Sub 78A, in which it repealed Commission Rules R8-56 through R8-59, and revised Rules R8-60 through R8-62 governing the IRP process. The new rules shorten the reported planning horizon to ten years. They also streamline the review process for the IRPs while retaining the filing of an annual plan by each utility in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under G.S. 62-110.1(c) and G.S. 62-2(3a). This annual report reflects the third round of IRP filings by the utilities under the new rules.

INTRODUCTION

The General Statutes of North Carolina require that the Utilities Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity for North Carolina. The statutes also require the Commission to submit an annual report to the Governor and the General Assembly regarding future electricity needs. G.S. 62-110.1 provides, in part, as follows:

"(c) The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Power Commission and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction.....Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such a plan, and the program of the Commission for the ensuing year in connection with such plan."

Information necessary to conduct the analysis of the long-range needs for future electric generating capacity pursuant to G.S. 62-110.1 is filed by each regulated utility as required in Rules R8-60 through R8-62 of the Utilities Commission as a part of the Least Cost Integrated Resource Planning process. The rules define an overall framework within which least cost integrated resource planning takes place in North Carolina. Least cost integrated resource planning, commonly called Integrated Resource Planning (IRP), is a strategy which considers conservation, load management, and other demand-side options along with new utility-owned generating plants, non-utility generation, and other supply-side options in order to identify those electric resource options which can be most cost-effective for the ratepayers consistent with adequate, reliable service.

This **annual report** is an update of the Commission's July 2000 Annual Report to the Governor and the General Assembly filed pursuant to G.S. 62-110.1(c). It is based primarily on the most current reports (as of April 30, 2001) to the Commission by the regulated electric utilities serving North Carolina regarding their respective analyses and plans for meeting the demand for electricity in their respective service areas, as well as other records and files of the Commission. The information contained in this report also reflects the hearings and analysis during proceedings held in early 2001 in Docket No. E-100, Sub 88, Investigation of Integrated Resource Planning in North Carolina - 2000. A final Order Approving Integrated Resource Plans was issued on April 4, 2001, in that docket.

OVERVIEW OF ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

There are three regulated electric investor-owned utilities (IOUs) and two university-owned utilities operating under the laws of the State of North Carolina and subject to the jurisdiction of the North Carolina Utilities Commission. All three of the IOUs own generating facilities. They are Carolina Power & Light Company (CP&L), whose corporate office is in Raleigh, North Carolina; Duke Power, A Duke Energy Company (Duke), whose corporate office is in Charlotte, North Carolina; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and who does business in North Carolina under the trade name Dominion North Carolina Power (NC Power). Duke and CP&L, the two largest electric IOUs in the state, together operate generating units that supply approximately 95% of the electricity consumed in the state. Approximately two-thirds of the utility business of both Duke and CP&L is located in North Carolina, with the remainder located in South Carolina. VEPCO operates generating units that supply approximately 5% of the electricity consumed in North Carolina. Approximately 5% of the utility business of VEPCO is located in North Carolina, as Dominion North Carolina Power, while the main portion of VEPCO's utility business is located in Virginia as Dominion Virginia Power.

Nantahala Power & Light Company (Nantahala), formerly a fourth electric IOU in the state, was given approval by the North Carolina Utilities Commission to merge into Duke Power Company by Order issued April 8, 1998, in Docket Nos. E-7, Sub 614, and E-13, Sub 178. The merger was consummated on August 3, 1998. Forecasts of the future electric power needs of Nantahala are incorporated into the overall planning of Duke.

The remaining two electric utilities are small transmission and distribution companies wholly located in North Carolina. Both of these utilities are university-owned: New River Light and Power, located in Boone, North Carolina; and Western Carolina University, located in Cullowhee, North Carolina. Forecasts of the future electric power needs of New River Light & Power and of Western Carolina University are incorporated into the overall wholesale market planning of the IOUs.

Approximately 20% of the IOUs' total electric sales in North Carolina are to the wholesale market in North Carolina, consisting primarily of electric membership cooperatives and municipally-owned electric systems. Forecasts of the future electric power needs of the wholesale market are incorporated into the overall integrated resource planning of the regulated IOUs.

Based primarily on annual reports (FERC Form 1) to the Commission for the 2000 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are as follows:

Table 1: Electricity Sales of Regulated Utilities In North Carolina - 2000

	NC Retail GWh*	NC Wholesale GWh*	Total GWh Sales* (NC Plus Other States)
CP&L	34,746.9	13,867.6	56,652.8
Duke	52,659.9	6,648.8	84,634.2
NC Power	3,358.9	1,708.6	76,155.4
New River	212.8	0	212.8
Western Carolina (1)	25.0	0	25.0

*GWh = 1 Million kWh

(1) Figures for Western Carolina University are estimated from its annual calculations for fuel charge adjustments.

There are 32 electric membership corporations (EMCs) serving over 750,000 customers in North Carolina, including 27 that are headquartered in the State and another five that are headquartered in adjacent states. These EMCs serve customers in over 90 counties in the State, and they serve at least 40% of the population in a third of these counties. Twenty-six of these EMCs are members of North Carolina Electric Membership Corporation (NCEMC), an umbrella service organization that acquires the electric power supplies needed by its 26 members. NCEMC acquires electric capacity for its participating EMCs primarily by means of wholesale purchases from the regulated electric utilities, but it also owns approximately 660 MW of its own generating facilities, consisting primarily of a partial interest in Duke's Catawba Nuclear Station. NCEMC has its principal office in Raleigh, North Carolina.

There are more than 70 municipally-owned electric distribution systems serving over 500,000 customers in North Carolina. Most of these municipally-owned systems are members of ElectriCities, an umbrella service organization for the cities. ElectriCities is a non-profit organization that consolidates many of the technical, administrative and management services needed by its 98 or so municipally-owned electric utility members in North Carolina, South Carolina, and Virginia. (New River Power and Light and Western Carolina University, two of the smaller regulated utilities, are members of ElectriCities.) ElectriCities is a service organization; not a power supplier. However, fifty-one of the North Carolina municipals are participants in one of two municipal power agencies which provide wholesale power to their membership. ElectriCities' largest activity is management of the two power agencies.

The North Carolina Eastern Municipal Power Agency (NCEMPA) is the wholesale supplier to 32 cities and towns in eastern North Carolina. NCEMPA owns portions of five generating facilities (640 MW of fossil and nuclear) operated by CP&L.

The other power agency is North Carolina Municipal Power Agency Number 1 (NCMPA-1) which is the wholesale supplier to 19 cities and towns in the Piedmont area of the state. NCMPA-1 has an ownership interest (858 MW) in the Catawba Nuclear Station operated by Duke.

The primary source of electric power for that portion of the municipally-owned electric systems' needs not supplied by the two power agencies is wholesale electric power furnished by the electric IOUs in the State. Other minor sources of wholesale electric power for the municipalities include Southeastern Power Administration (SEPA), Tennessee Valley Authority (TVA), and Saluda Electric Corporation.

The North Carolina Utilities Commission does not regulate the rates of municipally-owned electric systems or electric membership cooperatives; however, the Commission does have jurisdiction over licensing of new electric generating plants operated by municipalities or electric cooperatives. The Commission has also required participation by NCEMC in the Integrated Resource Planning process since 1993.

In addition to the regulation of electric utility rates and services of IOUs and jurisdiction over the construction of electric generating facilities in North Carolina, the North Carolina Utilities Commission also has jurisdiction over the construction of new electric transmission facilities (161 kV and above) in North Carolina, including those owned by municipals and cooperatives.

HISTORICAL PEAK DEMAND

North Carolina is considered a strong growth state, which is apparent when observing the peak electrical demands of each major electric utility illustrated in Tables 2, 3, and 4 below. For the period 1980 through 2000, each utility's summer peak demand has grown by almost 250 MW per year on average. During the period 1990 through 2000, the average annual growth in summer peak demand was more than 240 MW for each utility. This is roughly equivalent to the output of a sizable generating facility. The annual summer peak demand remains predominant over winter peak demand for integrated resource planning purposes.

After the 1973 Arab oil embargo, the electric utilities began initiating certain conservation and load management measures to control growth in both peak demand and energy usage. Most of the programs in effect today were implemented in the 1970's and 1980's. Without these demand-side management programs, growth in peak demand would have been greater than actually recorded.

The average annual growth rate in summer peak demand for electricity was approximately 3% for the 1980-2000 period. As shown in Tables 2, 3, and 4 below, the utilities have had relatively strong growth rates during 1980-2000. Note that peak demands contained in Table 2 are based on preliminary figures reported to the Public Staff weekly, rather than on figures reported in the annual reports (FERC Form 1) of each utility. The FERC Form 1 reports peak loads by calendar year, whereas the preliminary peak loads are reported by season and are more useful for calculating seasonal growth rates.

Table 2: Systemwide Peak Loads for CP&L, Duke, and NC Power Since 1980

	CP&L		Duke		NC Power	
	S	W*	S	W*	S	W*
1980	6,139 MW	6,402 MW	10,364 MW	10,530 MW	8,484 MW	8,451 MW
1985	6,867	7,763	11,204	12,586	9,819	9,836
1990	8,681	7,875	14,046	12,778	12,113	11,076
1995	10,155	9,810	16,888	15,855	14,003	14,910
2000	11,106	11,140	18,773	16,336	15,410	14,729
<i>*Winter peak following summer peak</i>						

Table 3: Average Annual rates of Growth in Summer Peak Load for CP&L, Duke, and NC Power Since 1980

Summer Peak	CP&L		Duke		NC Power	
1980-1985	147 MW	2.3%	168 MW	1.6%	267 MW	3.0%
1985-1990	361	4.8	568	4.8	459	4.3
1990-1995	295	3.2	568	3.8	378	2.9
1995-2000	190	1.8	377	2.1	281	1.9
1990-2000	243	2.5	473	2.9	330	2.4
1980-2000	248	3.0	420	3.0	346	3.0

Table 4: Average Annual Rates of Growth in Winter Peak Load for CP&L, Duke, and NC Power Since 1980

Winter Peak*	CP&L		Duke		NC Power	
	Peak (MW)	Rate (%)	Peak (MW)	Rate (%)	Peak (MW)	Rate (%)
1980-1985	272	3.9%	411	3.6%	277	3.1%
1985-1990	22	0.3	76	0.6	248	2.4
1990-1995	387	4.5	615	4.4	767	6.1
1995-2000	266	2.6	96	0.6	-36	-0.2
1990-2000	327	3.5	356	2.5	365	2.9
1980-2000	237	2.8	290	2.2	314	2.8
<i>*Following summer peak</i>						

LOAD FORECASTS

Forecasting electric load growth for many years into the future is an imprecise art at best. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future, and that historical correlations give meaningful clues to future behavioral patterns. As a result, any shift in such correlations or relationships can introduce significant errors into the forecast. A prime example of such a shift in historical relationships was the shift in energy usage patterns following the dramatic increase in fuel oil prices during the mid-1970's that resulted from the Arab oil embargo, an event which rendered virtually all prior forecasts invalid. A similar major shift in historical forecasting relationships may occur as a result of electric industry restructuring. The increasingly difficult forecasting that will come with industry restructuring can be mitigated to some degree by greater reliance on new capacity that requires shorter lead times for design and construction.

CP&L, Duke, and NC Power each utilize generally accepted forecasting procedures. Although their respective forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires the analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

With the inception of Integrated Resource Planning, North Carolina electric utilities have attempted to enhance forecasting accuracy by performing end-use forecasts. While this approach

relies on historical information, it includes specific electrical usages and consumption patterns in addition to general economic relationships.

Table 5 below illustrates the systemwide average annual rates of growth in energy and peak loads which are currently anticipated by CP&L, Duke, and NC Power. The growth rates are based on peak loads reduced by conservation, energy efficiency, and load management. **Detailed load projections for the respective utilities are shown in Appendices 1, 2, and 3.**

Table 5: Forecast Annual Rates of Growth for CP&L, Duke, and NC Power

	CP&L (2001-2010)		Duke (2001-2010)		NC Power (2001-2010)	
Summer Peak	307 MW	2.4%	400 MW	2.1%	141 MW	0.8%
Winter Peak	333 MW	2.5%	225 MW	1.4%	87 MW	0.6%
Energy	1,861 MWh	2.8%	2,197 MWh	2.1%	1,045 MWh	1.2%

The values shown in Table 5 for each utility are based on their respective IRPs filed on or about September 1, 2000. The values reflect their forecast loads after deducting DSM effects.

The values shown in Table 6 illustrate the variations in forecasts by CP&L, Duke, and NC Power in previous IRP proceedings.

Table 6: Previous Forecast Annual Rates of Growth in Summer Peak for CP&L, Duke, and NC Power

<i>Period Covered</i>	1999/0-2009	1998/9-2007/8	1997/8-20011/12*	1996-2010*
CP&L	3.1%	2.9%	2.5%	2.3%
Duke	1.8%	1.5%	1.8%	2.2%
NC Power	1.1%	1.4%	1.8%	1.9%

*Fifteen-year forecasts.

The current load forecasts adopted by the Commission are based in large part on the premise that conservation, load management, and emerging alternative energy resources represent permanent changes in customer energy use. However, uncertainties concerning the timing and predictability of the various demand reduction techniques under consideration make it necessary to allow flexibility in the planning for generation capacity expansion to match the forecasts.

North Carolina utility forecasts of future electrical load are consistent with forecasts of utilities in neighboring states and slightly greater than the nation as a whole. For example, the 2000-2009 Reliability Assessment by the North American Electric Reliability Council (NERC) indicates that the forecast of average annual growth in summer peak demand for the period is 2.4%. The report forecasts the average annual growth in energy usage at 2.4% also. (See NERC website at www.nerc.com).

DEMAND-SIDE RESOURCES

Demand-side management (DSM) resources, including conservation and load management measures, play a role in meeting the energy and demand requirements on the electric utility systems by controlling future loads. CP&L, Duke, and NC Power have used a variety of programs, such as bill credits for interruptible loads, cash incentives and/or low interest loans to encourage customers to install higher efficiency equipment, and special rate designs to discourage wasteful uses of electricity. These programs, which are all voluntary, are generally intended to lower the electric bills of participating customers and at the same time to reduce overall electricity costs to the remainder of the utility system as well.

Based on information contained in their current IRPs, CP&L, Duke, and NC Power expect to achieve DSM summer peak load reductions as shown in Table 7 below:

Table 7: Projected DSM Summer Peak Load Reductions

CP&L	377 MW by 2001	383 MW by 2010
Duke	1,003 MW by 2001	828 MW by 2010
NC Power	83 MW by 2001	54 MW by 2010

SUPPLY-SIDE RESOURCES

Traditionally, the regulated electric utilities in North Carolina have met customer electricity demand primarily by installing their own generating capacity. These generating plants are usually classified by fuel type (nuclear, coal, gas/oil, and hydro) and are generally placed into three varying categories of operation:

- (1) Base load - operates nearly full cycle;
- (2) Intermediate - cycles with load increase and decrease; and
- (3) Peaking - operates infrequently to meet system peak demand.

Nuclear and large coal facilities are operated as base load plants and typically operate more than 5000 hours annually. Smaller/older coal and oil/gas plants are operated as intermediate load plants and typically operate between 5,000 and 1,000 hours per year. Finally, combustion turbines and other similar plants are operated as peaking plants and usually operate less than 1,000 hours per year.

Another source of electric generation facilities in North Carolina utilized to supply the state's electric needs is non-utility generation. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA) establishing a national policy to encourage the efficient use of renewable fuel sources and cogeneration (production of electricity as well as another useful energy byproduct - generally steam - from a given fuel source). North Carolina electric utilities now utilize non-utility purchased power regularly as a supply resource.

The Commission has found in previous years that the most economical mix of electric generation for CP&L, Duke, and NC Power is a combination of hydroelectric generation, coal-fired and nuclear-fueled steam generation, combustion turbines, and purchased power. In addition, the Commission recognizes the need for a mix of base load facilities, intermediate or load-following facilities, and peaking facilities. Conservation, load management, and the development of alternative energy resources and demand-side options also play a significant role when considering the capacity needs of each utility.

The current **capacity mix** of each utility is illustrated in the following Table 8, consisting of the percentage of installed generating capacity (based on summer ratings) as listed in the most current IRPs filed by each utility.

Table 8: Installed Generating Capacity (Summer Ratings) for 2000

	CP&L	Duke	NC Power
Fossil Steam	48.2%	39.8%	53.8%
Nuclear Steam	29.0%	36.1%	24.0%
Hydroelectric	2.0%	14.5%	11.2%
Combustion Turbines	20.8%	9.6%	11.0%

The actual **generation mix** (based on kWh generated) for each utility reflects the operation of the capacity shown above, plus outside purchases, and the operating efficiencies achieved by utilizing each source of power as close to optimum as possible. Generally, plant use is determined by economic dispatch. For example, the actual generation produced and power purchased for each utility (based on monthly fuel reports filed with the Commission) are illustrated in Table 9.

Table 9: Total Energy Resources for CP&L, Duke, and NC Power for 2000

	CP&L	Duke	NC Power
Fossil Steam	50.1%	41.5%	46.6%
Nuclear Steam	39.6%	53.9%	36.8%
Hydroelectric	0.7%	0.1%	4.4%
Combustion Turbines	1.4%	0.4%	6.0%
Utility Purchases	5.6%	2.8%	1.8%
Non-Utility Purchases	2.6%	1.3%	4.4%

The purchases above include buyback transactions associated with jointly owned plants. The percent of MWh generation from nuclear units typically exceeds the percent of MW generating capacity represented by such units, reflecting the use of nuclear units for base-load generation. On the other hand, combustion turbines (CTs) usually contribute an insignificant amount of the fossil MWh generation, (typically less than 1%,) although they do represent a significant percentage of the MW generating capacity available to each utility, reflecting the use of CTs primarily for peak-load generation and standby capacity.

Based on information listed in the most current IRPs filed with the Commission, each utility has identified projected new **capacity additions**.

CP&L currently has 10,961 MW of installed generating capacity (summer rating, excluding purchases and non-utility capacity but including 640 MW jointly-owned by NCEMPA), based on its IRP filed September 1, 2000. The Company proposes to add 6,183 MW of new installed capacity during 2001-2010, primarily combustion turbines. This includes 2,645 MW of CTs for which there are specific plans and 3,280 MW of undesignated capacity. The Company also projects a 683 MW reduction in capacity in 2010 due to retirement of the Robinson nuclear unit.

Duke currently has 19,357 MW of installed generating capacity (summer rating, excluding purchases and non-utility capacity but including 858 MW jointly-owned by NCMPPA-1), based on its IRP filed September 1, 2000. The 19,357 MW includes 100 MW of Nantahala Power & Light installed hydro-electric generating capacity. Duke proposes to add 5,643 MW of new installed capacity during 2001-2010 but notes that the date of operation, the type of resource, and the size are not firm.

NC Power currently has 14,146 MW of installed generating capacity (summer rating, excluding purchases and non-utility capacity), based on its IRP filed September 1, 2000. The Company proposes to add approximately 722 MW of new installed CT capacity during 2001-2010.

RESERVE MARGINS

The reserve margin, which is the ratio of reserve capacity to actual needed capacity (i.e., peak load) provides an indicator of the ability of the electric utility system to continue to operate despite the loss of a large block of capacity (generating unit outage and/or loss of transmission facility), deratings of generating units in operation, and the load being greater than forecast. A similar indicator is capacity margin, which is the ratio of reserve capacity to total overall capacity (i.e., reserve capacity plus actual needed capacity.) A 20% reserve margin is the same as a 16.7% capacity margin. Although reserve margin was the industry standard term for many years, capacity margin has been the preferred industry standard term in recent years. Nevertheless, this report continues to utilize the reserve margin terminology for the sake of continuity.

It is difficult, if not impossible, to plan for major generating capacity additions in such a manner that constant reserve margins are maintained. The reserve margins will generally be less than optimum just prior to placing new generating units into service, and they will be greater than optimum just after new generating units are placed into service. Furthermore, the reserve margins must be adequate to account for a variety of uncertainties which are as yet undetermined, such as weather variations, the impact of regulatory policies regarding nuclear operations, clean air and other environmental concerns, customer responses to the various conservation and load management programs, and the overall direction of the economy.

Forecasted yearly reserves are contained in Appendices 1, 2, and 3 for CP&L, Duke, and NC Power respectively. The summer reserve margin and capacity margin ranges currently projected by each electric utility are illustrated in Table 10 below.

Table 10: Projected Reserves For CP&L, Duke, and NC Power

	Reserve Margins	Capacity Margins
CP&L (2001-2010)	11.7. - 14.5%	10.4 - 12.6%
Duke (2001-2010)	16.9 - 17.8%	14.4 - 15.1%
NC Power (2001-2010)	12.5%	11.1%

The 2000-2009 Reliability Assessment by the NERC indicates that the summer reserve margins for the Southeastern Electric Reliability Council (SERC) region will range from 12.7% to 13.2% during the 2000-2004 period. (See descriptions of NERC and SERC in the Reliability section.)

The NERC Reliability Assessment points out that resource planning is changing in the United States as the industry restructures. Generation developers are primarily driven by financial incentives and not maintenance of reserve margins. Reserve margins in the current NERC assessment show a marked improvement over those for the past three years primarily because of new merchant capacity projected to come on line. Shifting financial incentives for generation developers coupled with shorter lead times to construct new generating facilities result in a sharp decline in reported capacity

additions beyond 2004, indicating that decisions have not yet been made on such additions or are being withheld for competitive reasons. For example, CP&L includes over 3,000 MW undesignated generating capacity additions in its IRP for the planning period, and Duke likewise includes over 5,000 MW of such undesignated additions.

RELIABILITY

Reliability of electric power supply is the ability of any electric system to continuously supply all of the demands of its consumers with a minimum interruption of service. It is also the ability of an electric system to withstand sudden disturbances, such as short circuits or sudden loss of system components due to scheduled or unscheduled outages. The reliability of an electric system is determined by the number, size, fuel type, and age of the utility's power plants, the different types and numbers of interconnections the utility has with its neighboring electric utilities, and the environment to which its distribution and transmission systems are exposed.

There are several measurements of reliability utilized in the electric utility industry today. Generally, they are divided between probabilistic measures (loss of load probability, frequency, and duration of outages) and non-probabilistic measures (reserve margin, capacity margin). One of the most widely used measures is the reserve margin (or capacity margin). The reserve margin/capacity margin looks at the utility's capability compared to its peak demand. In earlier years, a 20% reserve margin was considered appropriate for long-range planning purposes. In more recent years, the Commission has approved IRPs containing less than 20% reserve margins for substantial periods into the future.

A major factor in achieving reliability is the interconnection of electric power systems across the country. For many years, it has been a federal policy to encourage interconnection and coordination among electric utilities in order to conserve energy, make more efficient use of facilities and resources, and to increase reliability. The NERC was formed by the electric power industry in 1968 to promote the reliability of bulk electric power supply in North America. NERC consists of ten regional reliability councils which together encompass virtually all of the electric power systems in the United States and Canada, plus a portion of Baja California in Mexico.

NERC is currently in the process of transforming itself from a voluntary system of reliability management to the North American Electric Reliability Organization (NAERO), an organization that will be mandatory in nature with the backing and support of governments. Once legislation is passed in the United States and the necessary rulemakings are approved, NERC will be ready to turn over its governance to NAERO. The fundamental change from NERC to NAERO is being driven by the fact that more and more "players" now have access to the electric grid, thereby shifting the balance between economic gain and reliability for stockholders and ratepayers alike. The mission of the new NAERO will be to develop, promote **and enforce** standards for a reliable North American bulk electric system.

Legislation that would authorize the transformation of NERC into NAERO passed the U.S. Senate in the last session, but the House failed to act. Similar legislation is expected to be introduced in the current session.

The SERC is one of the ten regional councils of NERC. Its 39 regular members and 34 associate members include investor-owned utilities, electric cooperatives, municipally-owned utilities, federal and state-owned systems, independent power producers, and power marketers. SERC is divided into four subregions: Southern (composed mostly of the Southern Company electric system centered in Georgia, Alabama, and Mississippi), TVA (containing the Tennessee Valley Authority area), VACAR (containing the Virginia-Carolinas area), and Entergy (containing primarily the Entergy operating areas in Louisiana, Arkansas and Missouri). VACAR consists of the CP&L, Duke, and NC Power operating areas in addition to the operating areas of four other utilities serving portions of Virginia, North Carolina, and South Carolina.

The 2000-2009 Reliability Assessment by NERC projects that SERC will have adequate capacity margins and capacity resources during the 2000-2009 period. The report indicates that 34,000 MW of net capacity additions are scheduled for the region during the period, with 35% of the total projected to come from uncommitted, undefined resources.

The report also indicates that the ability to transfer power over and above contractually committed uses has become marginal at some interconnection points on the grid. It described several measures SERC has taken to ensure reliability of the system. They include the establishment of five Security Coordinators, two of them in the VACAR subregion; the sharing of real-time information between the Coordinators; and implementation of line loading relief procedures. Nevertheless, SERC reports that the increase in bulk power marketing activities resulting from open access to the transmission grid will continue to push the operating state of the transmission system into conditions for which it was not originally planned.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

Commission Rule R8-60(b) specifies that Commission Rule R8-60 governing Least Cost Integrated Resource Planning (IRP) is applicable to the North Carolina Electric Membership Corporation. The Commission has concluded in previous proceedings that it was not necessary or appropriate to include individual EMCs in its IRP proceedings.

NCEMC is an umbrella service organization that acquires the electric power supplies needed by its 26 members, which are distribution cooperatives providing retail electric service to over 750,000 customers in North Carolina. Although NCEMC's member cooperatives operate 1 MW or so of their own generation, their contracts with NCEMC prohibit them from constructing further generation facilities of their own and also require them to remain members of NCEMC until well into the future. There are six distribution cooperatives operating in the state that are not members of NCEMC. Five are incorporated in contiguous states and provide service in limited areas across the

border into North Carolina. The sixth is French Broad EMC, which has agreed to provide appropriate information to NCEMC for inclusion in NCEMC's IRP filings.

NCEMC acquires electric capacity for its participating membership cooperatives primarily by means of wholesale purchases from the regulated electric utilities. NCEMC also owns approximately 662 MW of generation facilities, consisting primarily of a partial interest (a 644 MW share) in Duke's Catawba Nuclear Station plus two small peaking plants (at Ocracoke Station and at Buxton Station) on the Outer Banks.

NCEMC is a member of VACAR, a subregion of SERC, and participates on several committees of those reliability councils. NCEMC also participates in and closely monitors activities related to Regional Transmission Organizations (RTOs), and specifically, the Alliance RTO and the GridSouth RTO. (See section on Electric Industry Restructuring.) These two RTOs are being proposed for areas served by NCEMC members. NCEMC reports that these efforts are particularly important to it because of NCEMC's status as a transmission-dependent utility that relies on the transmission systems of Duke, CP&L, and NC Power to transfer the power it generates and the power it purchases to the approximately 267 delivery points of its member EMCs.

NCEMC's total load growth in North Carolina is projected to be approximately 3.1% per year during the 2000-2010 summer seasons. **(See Appendix 4.)** To meet this expected growth, NCEMC is relying primarily on firm purchases from CP&L, Duke, and NC Power in the near term, but it expects to rely primarily on currently undesignated purchases in the long run. Nevertheless, NCEMC expects a significant portion of its long-term purchases (greater than five years) to be tied to a distinct capacity resource located within the control areas of its current power suppliers.

NCEMC also reports that acquisition of increasing amounts of power at competitive wholesale rates has reduced the economic return of its load management and customer-owned generation programs. Nevertheless, NCEMC and its member EMCs expect to continue the availability of its existing programs.

INTEGRATED RESOURCE PLANNING

Integrated resource planning is a strategy which considers conservation, load management and other demand-side measures along with utility-owned generating plants, non-utility generation, and other supply-side resources in providing electric service. The primary thrust of the integrated resource planning strategy is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available resource options in order to identify those resource options which can be most cost-effective for the ratepayers consistent with adequate, reliable service.

By Commission Order dated December 8, 1988, in Docket No. E-100, Sub 54, Commission Rules R8-56 through R8-61 were adopted in order to define the framework within which integrated resource planning takes place. These rules incorporated the analysis of the probable electricity

growth and the long-range need for future electric generating capacity for North Carolina as required by Section 62-110.1(c) of the North Carolina General Statutes. By Order issued December 4, 1992, Rule R8-62 was added.

The first integrated resource plans (IRPs) of the electric utilities were filed with the Commission in April 1989, in Docket No. E-100, Sub 58, under the new rules established in 1988. On May 17, 1990, the Commission issued its Order Adopting Least Cost Integrated Resource Plans in which it found that the IRPs of CP&L, Duke, and NC Power were reasonable for purposes of that proceeding, and that NCEMC should be required to participate in all future IRP proceedings.

The Commission subsequently conducted a second and third full analysis and investigation of these matters resulting in its Order Adopting Least Cost Integrated Resource Plans on June 29, 1993, in Docket No. E-100, Sub 64, and its Order Adopting Least Cost Integrated Resource Plans on February 20, 1996, in Docket No. E-100, Sub 75.

On April 25, 1996, the Federal Energy Regulatory Commission (FERC) adopted its final rule (Order 888) regarding open access to the electric transmission grid. It also adopted its final rule (Order 889) regarding an Open Access Same-Time Information Systems (OASIS). On May 15, 1996, the North Carolina Utilities Commission issued its Order Requesting Comments in Docket No. E-100, Sub 78, in which it requested comments from the electric utilities under its jurisdiction and other interested parties regarding the probable impacts of FERC Orders 888 and 889. The resulting comments included numerous recommendations by the parties of ways to enhance wholesale competition and any benefits flowing to retail customers as a result of it. Almost all parties agreed, among other things, that the IRP process should be revised.

A subsequent round of comments included a general endorsement of the proposal that the two/three year IRP filings plus annual updates and short-term action plans be replaced by a single annual filing. There was also general support for a shorter planning horizon than the fifteen years required at that time. On April 29, 1998, the Commission issued its Order Adopting Revised Rules in Docket No. E-100, Sub 78A, in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62 governing the IRP process. The new rules shortened the reported planning horizon to ten years, and they streamlined the review process for the IRPs while retaining the filing of an annual plan by each utility in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under G.S. 62-110.1(c) and G.S. 62-2(3a).

On or about September 1, 1998, the first IRP filings were made under the revised rules by CP&L, Duke, NC Power, and NCEMC in Docket No. E-100, Sub 82. That proceeding resulted in the Commission's July 13, 1999 Order Adopting Least Cost Integrated Resource Plans and Clarifying Future Filing Requirements. The Commission concluded as a part of its Order that the reserve margins being forecast by CP&L, Duke, and NC Power indicate a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies. It commented that such a development was troubling in view of the electric industry restructuring that

has taken place so far and remains under further consideration in this State. The Commission stated that it would closely monitor the situation in future IRP reviews.

The second round of IRP filings in Docket No. E-100, Sub 84, resulted in the Commission's June 21, 2000, Order Adopting Integrated Resource Plans. The Commission recognized in the Order that the electric power industry is in the midst of a time of economic and regulatory transition and that the resulting changes have led to the rethinking of certain long-accepted industry standards. As a result of these changes and the amount of information contained in the record, the Commission stated that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at this time. For this reason, the Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission stated that it had no reason to believe that existing generation resources are inadequate in light of current conditions. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it will be actively monitoring the adequacy of existing electric utility reserve margins, and that it will take appropriate action in the event that any reliability problems develop.

The third round of IRP filings in Docket No. E-100, Sub 88, resulted in the Commission's April 4, 2001, Order Adopting Integrated Resource Plans. The Commission reiterated its comments in the previous proceedings regarding generating reserve margins and transmission adequacy, concluding that existing generation resources are adequate in light of current conditions. **A copy of the April 4, 2001, Order is attached hereto as Appendix 5.**

ELECTRIC INDUSTRY RESTRUCTURING

As stated above, on April 25, 1996, the FERC issued its Orders 888 and 889 establishing its rules governing open access to electric transmission systems by wholesale customers and establishing an Open Access Same-time Information System (OASIS), respectively. The FERC rules required utilities to file standard, non-discriminatory open access transmission tariffs for wholesale customers by July 11, 1996, generally based upon a pro-forma tariff adopted by FERC. They also required the utilities to take steps to apply the open-access tariffs to wholesale transactions under existing bilateral economy energy agreements by December 31, 1996.

The FERC rules also required utilities to separate/unbundle their transmission functions and their power marketing functions applicable to wholesale transactions. They also required utilities to obtain information about their own transmission system for their own wholesale transactions in the same manner as their competitors via an OASIS system on the Internet. The purpose was to ensure that transmission owners do not have an unfair advantage in using transmission systems to sell power.

The FERC rules also permitted recovery of legitimate, prudent, verifiable costs for wholesale service contracts executed on or before July 11, 1994.

On May 5, 1996, the North Carolina Utilities Commission issued its Order Requesting Comments in Docket No. E-100, Sub 78, a proceeding established to investigate emerging issues in electric industry restructuring. The Order requested comments from the electric IOUs regarding the probable impacts of FERC Orders 888 and 889, and it provided for reply comments from interested parties. The purpose of the comments was to establish a dialog between the Commission and interested parties regarding wholesale competition in the electric industry.

CP&L, Duke, and NC Power all responded that they took the actions necessary to comply with the deadlines contained in Orders 888 and 889. They also took appropriate steps to mitigate their exposure to stranded costs. CP&L reported that it had renegotiated contracts with 98% of its wholesale load. NC Power reported that it had renegotiated contracts with "virtually all" of its wholesale load. Duke reported that it intends to present stranded cost claims to any customer who initiates proceedings before the FERC to modify existing contracts.

The North Carolina General Assembly passed legislation during the 1997 session establishing the Study Commission on the Future of Electric Service in North Carolina. The Study Commission is charged with examining the cost, adequacy, availability, and pricing of electric rates and services in North Carolina to determine whether legislation is necessary to assure an adequate and reliable source of electricity and economical, fair, and equitable rates for all consumers of electricity in North Carolina.

Included in the list of issues which the Study Commission is directed to address are: (1) customer choice of electric providers; (2) obligation to serve and the obligation to receive service; (3) universal access to electric energy and assignment of responsibility to provide it; (4) clarification of state and federal jurisdiction; (5) stranded investment costs and benefits; (6) functional unbundling of generation, transmission, and distribution services; (7) impact of competition on the environment, low-income customers, conservation and efficiency programs, economic development, and tax revenues; and (8) anti-competitive conduct or exercise of market power.

On April 3, 2000, the Study Commission approved its final recommendations to the 2000 Regular Session of the 1999 General Assembly. Its recommendations include, among other things, (1) fully competitive retail electric service to all consumers in North Carolina as of January 1, 2006, and (2) recovery of reasonable potentially stranded costs by the incumbent utilities serving North Carolina. The Study Commission will also recommend specific legislative language necessary to accomplish its recommendations to the 2001 General Assembly and, where necessary, the 2003 General Assembly. **A copy of the Study Commission recommendations is attached as Appendix 6.**

At the Study Commission meeting held on January 23, 2001, the Study Commission redirected its focus to encouraging a robust and competitive wholesale market. Consistent with that new focus, Senator Hoyle, as Co-Chair of the Study Commission, asked the Utilities Commission to review the requirement for certification of new electric generating capacity in North Carolina with a view toward streamlining the certification process. In response, the Commission issued an Order on

February 7, 2001, in Docket No. E-100, Sub 85, which requested proposals and comments on what filing requirements are appropriate for certification of merchant plants, what new or revised Commission Rules should be adopted to implement such filing requirements, and how Commission procedures for certification of merchant plants may be streamlined. On March 14, 2001, the Public Staff filed a proposed rule. Numerous other parties filed comments and reply comments which identified several issues for Commission decision. On May 21, 2001, the Commission issued an Order which adopted a final rule (Commission Rule R8-63) regarding the certification process for merchant plants. The Commission believes the new rule significantly streamlines the certification of new merchant plants in North Carolina and greatly reduces the burden on applicants. The new rule eliminated a 120-day prefiling requirement which previously existed for merchant plant applications, spells out filing requirements and procedures in clear detail for merchant plant applications, and establishes a flexible standard by which an applicant can show the need for a new merchant plant. This new rule should significantly facilitate merchant plant construction in North Carolina.

The U.S. Congress is also considering legislation intended to hasten retail competition in the electric utility industry. The North Carolina Utilities Commission has responded to inquiries from the U.S. House Commerce Committee that any federal legislation should also address the issues described above (by the North Carolina General Assembly) in a manner which recognizes legitimate differences among states and does not place upward pressure on electricity rates in the lower cost states.

On December 20, 1999, the FERC issued its Order 2000 encouraging all transmission owners to voluntarily join regional transmission organizations (RTOs) to help address the engineering and economic inefficiencies inherent in the current transmission system and to correct perceived or real discrimination by transmission owners. Order 2000 does not require RTO participation, nor does it draw regional RTO boundaries. However, it states that FERC will consider requiring RTO participation as a condition for approval of mergers, acquisitions or market-based rates, or as a remedy for a discrimination complaint on a case-by-case basis. Order 2000 establishes a goal of having RTOs up and running by December 15, 2001, and requires each jurisdictional transmission owner or operator, by October 15, 2000, to (a) file an application for approval to participate in a specific RTO, or (b) explain its reasons for not participating in an RTO and any actions it is taking to resolve obstacles to participating in an RTO. Each RTO is subject to final approval by the FERC.

Duke, CP&L and South Carolina Electric & Gas Company (SCE&G) are presently engaged in a joint effort to develop the GridSouth RTO. GridSouth RTO will be a for-profit, independent transmission company incorporated in Delaware and operated by an independent, self-perpetuating board of seven directors serving staggered, three-year terms who must each be independent from market participants. GridSouth will have functional control of the transmission assets owned by its member utilities; it will have primary responsibility for planning and coordinating the RTO-wide transmission system; and it will have authority over transmission expansions within the RTO. The intent of the three utilities who are developing GridSouth is to create a framework that may lead to a broad, regional independent transmission company that spans the Southeast. CP&L and Duke have

sought approval from the North Carolina Utilities Commission to transfer operating control of their transmission assets to the GridSouth RTO, and such approval is still pending.

VEPCO (as Dominion Virginia Power and Dominion North Carolina Power) has joined with nine other utilities from Virginia to the upper midwest to form the Alliance RTO. The organization and governance of the Alliance RTO is similar to the GridSouth RTO. A recent settlement between the Alliance RTO and the Midwest Independent System Operator (MISO) will allow consumers in northeastern North Carolina access to electric generation from as far away as Minnesota. Final approval of the Alliance-MISO agreement as well as final approval of the Alliance RTO itself is still pending before the FERC. VEPCO (as Dominion North Carolina Power) has not yet sought approval from the North Carolina Utilities Commission to transfer operating control of its transmission assets to the Alliance RTO.

SUMMARY

The major electric utilities serving North Carolina continue to forecast rates of load growth that will be generally lower than they have experienced over the past 20 years. Their forecasts are relatively typical for electric utilities serving the southeastern states.

The major North Carolina utilities will also continue to depend on coal-fired and nuclear-fueled steam generation to produce the bulk of their electric output. They are projecting reserve margins that will be generally in the range that is typical for electric utilities serving the southeastern states but will be generally lower than the North Carolina utilities have maintained in the past.

The current reliability assessment by NERC projects that the SERC region will have adequate reserve margins over the next ten years but points out that much of its projection is based on planned capacity additions that are uncommitted, undefined resources. This indicates that utilities are planning to acquire new capacity with significantly shorter lead times, an approach typically associated with combustion turbine peaking plants. The increasing dependence on uncommitted resources is also representative of the approach being taken by the North Carolina utilities.