INDEPENDENT SPENT FUEL STORAGE INSTALLATION

LICENSE APPLICATION

H. B. Robinson Steam Electric Plant

CP&L

Carolina Power & Light Company

72-3

UNITED STATES

NUCLEAR REGULATORY COMMISSION

In the matter of)
CAROLINA POWER & LIGHT COMPANY)
H. B. ROBINSON STEAM ELECTRIC PLANT)
INDEPENDENT SPENT FUEL STORAGE INSTALLATION)

LICENSE APPLICATION

UNDER

10 CFR PART 72

(980SAR/pgp)

24823

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CHAPTER 1

GENERAL AND FINANCIAL INFORMATION

1. NAME OF APPLICANT

Carolina Power & Light Company (CP&L)

2. ADDRESS OF APPLICANT

CP&L
P.O. Box 1551
411 Fayetteville Street Mall
Raleigh, North Carolina 27602

3. DESCRIPTION OF BUSINESS OF APPLICANT

CP&L is an electric utility engaged exclusively in the generation, purchase, transmission, distribution, and sale of electric energy. The territory served by CP&L, an area of approximately 30,000 square miles, includes a substantial portion of the Coastal Plain in North Carolina extending to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section in North Carolina and in South Carolina and an area in western North Carolina in and around the city of Asheville. The estimated total population of the service area is approximately 3 million. As of December 31, 1983, CP&L furnished electric service to approximately 796,000 customers.

CP&L's facilities in Asheville and vicinity are connected with CP&L's system in other areas served by CP&L through the facilities of Duke Power Company, so that power may be transferred from or to the Asheville area through such interconnections. There are also interconnections with the facilities of Appalachian Power Company, Tennessee Valley Authority, Virginia Electric and Power Company, South Carolina Electric & Gas Company, South Carolina Public Service Authority, and Yadkin, Inc.

As of December 31, 1983, CP&L owned and operated nine steam electric generating plants with a maximum dependable capability of 7,518,000 KW, four hydroelectric plants with a net capability of 214,000 KW and internal combustion turbine generating units with a net capability of 1,018,000 KW. One 900,000 KW nuclear generating unit is scheduled for operation in 1986 and one 720,000 KW fossil fueled steam electric generating unit is scheduled for completion in 1991.

4. LEGAL STATUS

CP&L is a public service corporation formed under the laws of North Carolina in 1926.

The names and addresses of CP&L's directors and principal officers. all of whom are citizens of the United States, are as follows:

Directors:

Sherwood H. Smith, Jr.; Chairman, Raleigh, North Carolina
Daniel D. Cameron, Sr.; Wilmington, North Carolina
Felton J. Capel; Southern Pines, North Carolina
George H. V. Cecil; Asheville, North Carolina
Charles W. Coker, Jr.; Hartsville, South Carolina
William E. Graham, Jr.; Raleigh, North Carolina
Margaret T. Harper; Southport, North Carolina
Karl G. Hudson, Jr.; Raleigh, North Carolina
Gordon G. Hulbert; Pittsburgh, Pennsylvania
Edward G. Lilly, Jr.; Raleigh, North Carolina
John G. Medlin, Jr.; Winston-Salem, North Carolina
A. C. Monk, Jr.; Farmville, North Carolina
Horace L. Tilghman, Jr.; Marion, South Carolina
E. E. Utley; Raleigh, North Carolina

Principal Officers:

Name	Position
Sherwood H. Smith, Jr.	Chairman/President and Chief Executive Officer
E. E. Utley	Executive Vice President and Chief Operating Officer
Edward G. Lilly, Jr.	Executive Vice President and Chief Financial Officer
William E. Graham, Jr.	Executive Vice President
Charles D. Barham, Jr.	Senior Vice President and General Counsel
James M. Davis, Jr.	Senior Vice President
Lynn W. Eury	Senior Vice President
Russell H. Lee	Senior Vice President
M. A. McDuffie	Senior Vice President
Wilson W. Morgan	Senior Vice President
J. L. Lancaster, Jr.	Secretary
L. T. Quarles	Treasurer
Paul S. Bradshaw	Vice President and Controller

The address of the foregoing principal officers of CP&L is:

Post Office Box 1551
411 Fayetteville Street Mall
Raleigh, North Carolina 27602

The applicant is not owned, controlled, or dominated by an alien, foreign corporation or foreign government. The applicant makes this application on its own behalf and is not acting as agent or representative of any other person.

5. FINANCIAL QUALIFICATION OF APPLICANT

CP&L is an established New York Stock Exchange listed corporation with capital stock and retained earnings which totaled approximately $2,087,244,000 at December 31, 1983. Quarterly dividends on Common Stock have been paid in each year since 1946, the year CP&L Common Stock became publicly held. All applicable dividends on Preferred and Preference stocks accruing since CP&L's incorporation in 1926 have been paid.

CP&L's Annual Report to Shareholders for the year ended December 31, 1983, is attached as Appendix A. A copy of CP&L's Annual Report to the Securities and Exchange Commission (Form 10-K) for the year ending December 31, 1983, is included as Appendix B.

The funds necessary to operate and shut down the facility will be derived from operating revenues associated with the sale of electricity. As a regulated public utility, CP&L has reasonable assurance that rates established to cover its cost of producing electricity will be sufficient to cover operating and decommissioning costs of the independent spent fuel storage installation.

CHAPTER 2

TECHNICAL QUALIFICATIONS

As discussed in Chapter 9 of the Safety Analysis Report (SAR), CP&L currently has an adequate staff to construct and operate the Independent Spent Fuel Storage Installation (ISFSI). The ISFSI to be located at the H. B. Robinson Steam Electric Plant (HBR) utilizes a generic design by NUTECH Engineers, Inc., the NUTECH Horizontal Modular Storage (NUHOMS) System. Carolina Power & Light Company engineers have worked in conjunction with NUTECH to develop the site-specific design. Carolina Power & Light Company is, therefore, knowledgeable in all aspects of the project. Training for the operating phase is required and is discussed in Chapter 9 of the SAR.

Carolina Power & Light Company hereby commits to staff the project with an adequate cadre of personnel possessing the required skills throughout all phases of the project.

CHAPTER 3

TECHNICAL INFORMATION;

SAFETY ANALYSIS REPORT (SAR)

Carolina Power & Light Company intends to construct and operate an ISFSI at its H. B. Robinson Steam Electric Plant to provide long-term interim storage for irradiated fuel assemblies which have been out of the reactor and stored in the existing spent fuel pool. The facility to be installed is based on the system which has been developed by NUTECH Engineers, Inc., of San Jose, California; the NUTECH Horizontal Modular Storage (NUHOMS) System. The SAR describing the technical information for the HBR ISFSI is provided as an attachment to this License Application.

The NUHOMS System is a totally passive installation that is designed by analysis to provide shielding and safe confinement of irradiated fuel. The dry storage canister and horizontal storage module have been designed to function during and withstand certain accidents as described in the attached SAR.

The fuel assemblies to be stored in the ISFSI are currently located in the HBR Unit 2 (HBR2) spent fuel pool and were irradiated in the HBR2 reactor. Seven fuel assemblies are stored in each dry shielded canister. One dry shielded canister is stored in each concrete module. The fuel assemblies are confined in a helium atmosphere by the stainless steel canister. The canister is protected and shielded by the concrete module. Decay heat is removed by thermal radiation, conduction, and convection from the canister to an air plenum inside the concrete module. Air flows through this internal plenum by natural draft convection.

The canister and irradiated fuel assemblies are transferred from the HBR2 spent fuel pool to the concrete module in a transfer cask (GE IF-300 shipping cask owned by CP&L). The cask is precisely aligned and the canister is inserted into the module by means of a hydraulic ram.

This License Application by CP&L requests a license to construct and operate a total of eight modules. CP&L initially intends to construct three modules. Construction of the ISFSI will take approximately one year. In accordance with CP&L's agreements with the U. S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI), the first year of operation of the three module ISFSI will be part of a test program. Normal operation of the facility will continue past the first year for up to 20 years under the initial license until a permanent federal repository is available to store the spent fuel. CP&L may expand the facility to eight modules in the future if more storage becomes necessary.

CHAPTER 4

CONFORMITY TO GENERAL DESIGN CRITERIA

The HBR ISFSI will demonstrate the long-term storage of irradiated fuel assemblies (IFAs) in a dry environment. The HBR ISFSI is based on the NUHOMS System and is composed of a series of reinforced concrete horizontal storage modules (HSM). Each HSM will house a stainless steel helium filled dry shielded canister (DSC) containing seven IFAs. The sealed DSC serves as the confinement vessel for the IFAs while the HSM provides the biological shielding as well as a passive heat removal system for the decay heat of the IFAs. Each modular unit of this facility is capable of storing up to seven pressurized water reactor (PWR) fuel assemblies as described in Section 3.1 of the attached SAR.

The mechanical and structural designs of the DSC are based on the physical characteristics of the PWR IFAs to be stored within the DSC. The physical characteristics of the PWR IFAs to be stored at the HBR ISFSI are presented in Table 3.1-1 of the SAR. Additional information on the physical characteristics of these fuel assemblies is contained in Section 4.2 of the HBR2 Updated Final Safety Analysis Report (FSAR).

Table 3.3-1 of the SAR lists the features of the ISFSI which are important to safety (safety related). Chapter 6 of this License Application and Chapter 11 of the SAR discuss the quality standards to be applied to these features. Chapter 3 of the SAR describes the design criteria used for the HBR ISFSI. These criteria establish the design, fabrication, construction, testing, and performance requirements for the structures and components listed in Table 3.3-1. These structures and components are designed to withstand the effects of natural phenoma postulated to occur at the Robinson site without impairing their capability to perform safety functions (see SAR Chapters 2 and 3).

The heat generation per fuel assembly will be limited to one kilowatt per assembly. This results in a maximum of seven kilowatts per DSC. Fuel that has been irradiated to less than 35,000 MWd/MT and cooled for five years will meet this criteria. The assemblies will be checked (by analysis or by examination of appropriate records) to verify that they meet the physical, thermal, and radiological criteria. The principal design criteria for acceptable radiological and thermal characteristics are provided in Table 1.2-1 of the SAR.

The facility is designed to be totally passive, requiring no utilities or waste processing systems and to utilize HBR2's existing cask handling, fuel handling and associated auxiliary equipment in preparing the IFAs for dry storage. The cask to be used for the onsite transfer operation is the GE IF-300 shipping cask which is fully documented in Reference 3.5 of the SAR.

Spent fuel handling, transfer and storage systems shall be designed to maintain subcriticality and to prevent a nuclear criticality accident. Section 3.3.4 of the SAR addresses nuclear criticality safety.

Structures, systems, and components relating to fuel handling activities and storage shall be designed, fabricated, located, shielded, controlled, and tested to control external and internal radiation exposures to personnel (see Chapter 7 which provides information on specific fuel handling operations and radiation exposures).

The HSMs which house the DSCs are located on a level, reinforced concrete, load bearing slab. The slab is designed for normal and postulated accident conditions (see Section 8.3). The HSM is also designed to maintain its structural integrity during postulated environmental and geological events.

The design of the ISFSI incorporates considerations for decommissioning. Provisions are made to facilitate decontamination of structures and components, and minimize the quantity of, and facilitate the removal of, contaminated materials (see Section 3.5 of the SAR).

CHAPTER 5

OPERATING PROCEDURES; ADMINISTRATIVE AND MANAGEMENT CONTROLS

Procedures for operation of the HBR ISFSI will be developed by the appropriate CP&L personnel and incorporated into existing HBR2 procedures. Operation of the ISFSI will consist of loading fuel into canisters, sealing the canisters, transporting the canisters to the module, and loading/unloading of the canisters into the modules. During the one year demonstration program, provisions will be made to return the DSC to the spent fuel pool, if necessary.

Existing HBR2 procedures for handling irradiated fuel in the spent fuel pool, loading of the GE IF-300 shipping cask, and handling by the spent fuel building crane will also be utilized.

Administrative and management controls will be incorporated into the Plant Operating Manual system. These controls will include administrative systems and procedures, record keeping, review, audit and reporting necessary to ensure that the operation of the ISFSI is performed in a safe manner. Fuel selection will be independently verified to ensure conformance with the Technical Specifications (see Chapter 10 of the SAR).

CHAPTER 6

QUALITY ASSURANCE PROGRAM

All phases of the ISFSI will be performed under the guidance of applicable portions of the CP&L Corporate Quality Assurance (QA) Program and applicable QA requirements delineated in the HBR2 Updated FSAR. Controls will be established for the applicable activities which CP&L will perform as well as for those appropriate activities which subcontractors will perform.

Quality Assurance personnel in CP&L's Corporate QA Department perform oversight to assure that appropriate quality requirements are being met in the normal implementation of technical programs. Work associated with this project will be performed in the same way as other nuclear plant related activities, and will therefore be covered by the normal surveillance and audit process.

CHAPTER 7

OPERATOR TRAINING

The existing training program for HBR2 will be modified to incorporate the operation of the ISFSI into the program. Since the ISFSI is essentially a passive structure having no equipment or instrumentation required for normal operation, the training program will concentrate on abnormal events and initial fuel handling activities. The HBR2 Radiation Protection Training Program and Fire Protection Program will be expanded to cover the ISFSI. These training programs are expected to concentrate on fuel handling, canister loading/unloading, canister welding, canister/module interactions, and retrieval.

The HBR2 Replacement Training and Annual Retraining Program will be updated to include the ISFSI as part of the HBR2 program.

CHAPTER 8

INVENTORY AND RECORDS REQUIREMENTS

Special Nuclear Material (SNM) records are currently maintained for HBR2 showing the receipt, inventory, disposition, and transfer of all SNM (including nuclear fuel in CP&L's possession). This record system meets the requirements of 10CFR Part 70 for Special Nuclear Material.

The fuel to be stored in the HBR2 ISFSI will utilize the current HBR2 records system.

CHAPTER 9

PHYSICAL PROTECTION

The Physical Security Program, including a physical security plan, a design for physical protection, and a safeguards contingency plan, for the HBR2 ISFSI will be incorporated into the HBR2 Facility Security Plan. The plan is safeguards information and is protected and controlled in accordance with 10CFR73.21. The ISFSI portion of the HBR2 Facility Security Plan will be provided under separate cover.

CHAPTER 10

DECOMMISSIONING PLAN

The construction and operation of the ISFSI to be conducted at HBR2 makes provisions for the dry storage canister to be transferred to a federal repository when such a facility becomes operational. The concrete storage module is designed so that the canister can be safely returned to a shipping cask and transported off-site to the federal facility.

The shipping cask design and transportation requirements will depend on the regulations in effect at the time when the federal facility begins receiving spent fuel. In the absence of new regulations, the existing GE IF-300 shipping cask (owned by CP&L) would be used to transport the canisters.

Upon removal of the canisters, the level of contamination within the concrete module is expected to be extremely low and would be removed so that the concrete could be broken-up by conventional methods and removed.

CHAPTER 11

EMERGENCY PLAN

The Emergency Program for HBR2 has been determined to be adequate for events which might occur involving the ISFSI. The Emergency Program consists of the Robinson Radiological Emergency Plan and its implementing Plant Emergency Procedures. Also included are related radiological emergency plans and procedures of state and local organizations. The purpose of these programs is to provide protection of plant personnel and the general public and to prevent or mitigate property damage which could result from an emergency at the Robinson Plant. The combined emergency preparedness programs have the following objectives:

1. Effective coordination of emergency activities among all organizations having a response role.

2. Early warning and clear instructions to the population-at-risk in the event of a serious radiological emergency.

3. Continued assessment of actual or potential consequences both on-site and off-site.

4. Effective and timely implementation of emergency measures.

5. Continued maintenance of an adequate state of emergency preparedness.

The Robinson Radiological Emergency Plan has been prepared in accordance with Section 50.47 and Appendix E, of Title 10, Part 50, of the Code of Federal Regulations. The Plan shall be implemented whenever an emergency situation is indicated. Radiological emergencies can vary in severity from the occurrence of an abnormal event, such as a minor fire with no radiological health consequences, to nuclear accidents having substantial onsite and/or offsite consequences.

In addition to emergencies involving a release of radioactive materials, events such as security threats or breaches, fires, electrical system disturbances, and natural phenomena that have the potential for involving radioactive materials are included in the Plan. Other types of emergencies that do not have a potential for involving radioactive materials are not included in the Plan.

The activities and responsibilities of outside agencies providing an emergency response role at the Robinson Plant are summarized in the Plan (for completeness) and detailed in the State Emergency Plans.

The Plan provides the basis for performing advance planning and for defining specific requirements and commitments to be implemented by other documents and procedures. The HBR2 procedures provide the detailed actions and instructions which will be required to implement the Plan in the event of an emergency.

The Robinson Radiological Emergency Plan describes the general nature of emergency response activities, the available emergency response resources and facilities, and the means for maintaining the emergency preparedness. Specific plant implementing procedures have been developed to describe in detail how involved plant and corporate personnel carry out their specific responsibilities identified in the Plan.

CHAPTER 12

ENVIRONMENTAL REPORT

The intent of this chapter is to evaluate any environmental effects of the Independent Spent Fuel Storage Installation (ISFSI) which may exceed those resulting from normal plant operation. Construction activities will be carried out in conformance with local, state, and federal regulations. Following the construction of the horizontal concrete storage modules and installation of the canisters, the environmental impacts resulting from this program are expected to return to those existing before the initiation of the test program or to be less than those previously existing.

The ISFSI at H. B. Robinson Steam Electric Plant Unit No. 2 (HBR2) requires the commitment of various irretrievable building materials. The quantity of building materials to be used are small when compared to the materials required to construct an additional spent fuel pool.

The ISFSI will have minimal impact on the existing site plan layout. This minimal impact consists of the initial foundation (for three modules) and possible future construction of a separate foundation for five additional modules. The eight modules will encompass a total area of 0.15 acre. The second foundation will be constructed nearby, but separate from the initial three. It has been determined that future construction of the additional five modules will not have any impact on continued operation of the initial three modules. No new land resources will be required for this project as this activity will occur on CP&L owned property which is currently part of land being utilized for HBR2.

During the construction phase for the storage modules, loading of spent fuel into the canisters, and placement of the canisters into the storage module, water will be supplied from existing HBR2 sources. No new water sources will be required for initiating or carrying out the test program. All water generated in the HBR2 spent fuel pool area during the loading of spent fuel into the canister will be handled under existing HBR2 procedures for preparing spent fuel for shipments.

Construction activities related to the ISFSI will satisfy applicable laws that are in force at the time. These activities will have a negligible effect on noise levels, dust, or smoke.

Actual construction noise sources of the Steam Generator Replacement Outage (SGRO) during 1984 are used as reference levels for the H. B. Robinson site and site boundary, since they caused no objectionable situations to the local residents. Noise from the planned construction and operation of the ISFSI at the site boundary will not exceed that experienced during the SGRO. Based on the location of the plant site in a low population area and the limited amount of construction equipment required, noise resulting from the construction and operation of the ISFSI is expected to have negligible additional impact on the local area.

To protect personnel located on the site, Occupational Safety and Health Administration Standards (OSHA) will be followed.

CHAPTER 13

PROPOSED LICENSE CONDITIONS

The ISFSI to be constructed and operated at the HBR2 site will be incorporated into existing HBR2 procedures and programs for administrative and management control (see Chapter 5), including plant modification procedures, which include testing prior to startup. The construction and operation of the ISFSI will be performed under the guidance of applicable portions of the existing CP&L Corporate Quality Assurance Program (see Chapter 6).

The HBR2 ISFSI is a totally passive system which requires no monitoring instrumentation and a minimum of operating controls. Chapter 10 of the SAR provides the proposed limiting conditions of operation and surveillance requirements.

CHAPTER 14

CONCLUSION

Carolina Power & Light Company respectfully requests that the Nuclear Regulatory Commission issue a license under 10 CFR Part 72 to authorize the activities described in this application and the referenced documents for CP&L to construct and operate an eight module ISFSI. The Company commits to conduct activities associated with the HBR ISFSI in accordance with the requirements of 10CFR Part 72.

CAROLINA POWER & LIGHT COMPANY

BY: ______________________

E. E. Utley
Executive Vice President
Power Supply and Engineering &
Construction Groups

E. E. Utley, having been first duly sworn, did depose and say that the information contained herein is true and correct to the best of his information, knowledge and belief; and the sources of his information are officers, employees, contractors, and agents of Carolina Power & Light Company.

Lisa M. Randall / 2/14/85
Notary (Seal)

My commission expires: 5/18/88

LISA RANDALL
NOTARY
***
PUBLIC
WAKE COUNTY, N.C.

APPENDIX A

Carolina Power & Light Company

75

Years of Service

1908-1983

Annual Report 1983

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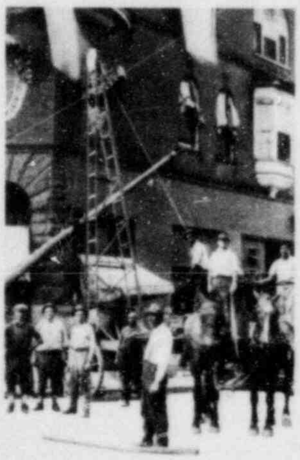


Annual Meeting

The 1984 Annual Meeting of Shareholders will be held in room D-1 of the Civic Center, 500 Fayetteville Street Mall, in downtown Raleigh, North Carolina, on May 16 at 10 a.m. (Those attending should enter the Center from the Wilmington Street side.) A formal notice of the meeting, a proxy statement and a form of proxy will be mailed in early April.

Transfer Agents and Registrars

For Common Stock and Preference Stock:
Wachovia Bank & Trust Company, N.A.
Winston-Salem, N.C. 27102

Bradford Trust Company
New York, N.Y. 10004

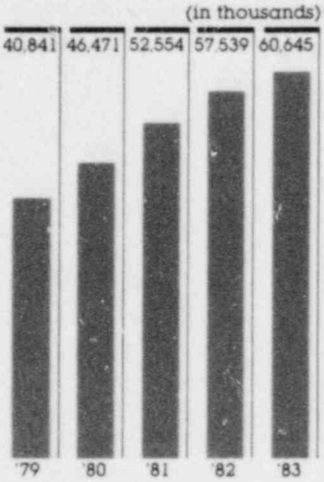
For Preferred Stock:
Wachovia Bank & Trust Company, N.A.
Winston-Salem, N.C. 27102

This Annual Report is submitted for the information of shareholders. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

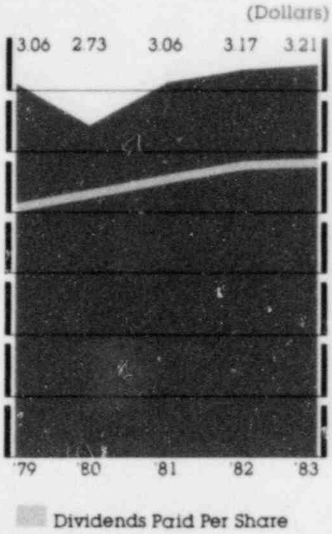
Carolina Power & Light Company
411 Fayetteville Street
Raleigh, North Carolina 27602

Earnings and Dividends Per Share of Common Stock

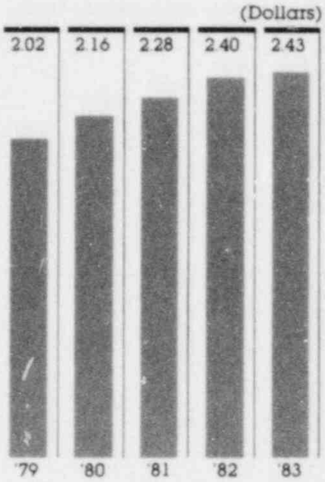
Average Shares Outstanding



Earnings Per Share



Dividends Paid Per Share



Summary of Quarterly Financial Data

(Composite Transactions-Reported Prices
Traded on the New York and Pacific Stock Exchanges)

(Amount in thousands except for per share data)

1982	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues	$405,559	$359,935	$402,342	$370,329
Operating Income	90,134	44,750	57,768	55,473
Net Income	81,455	37,722	55,232	52,738
Earnings Per Common Share	1.24	.46	.76	.71
Dividend Paid Per Common Share	.60	.60	.60	.60
Common Stock Price Per Share:				
High	23	22¾	22¾	21⅞
Low	19½	19⅝	19	18⅞

1983	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues	$416,638	$361,370	$448,720	$420,455
Operating Income	81,359	49,853	69,540	63,204
Net Income	78,460	44,438	60,182	56,189
Earnings Per Common Share	1.13	.55	.80	.72
Dividend Paid Per Common Share	.60	.60	.60	.63
Common Stock Price Per Share:				
High	23	22⅞	23¾	25⅛
Low	20⅝	21½	20⅜	21½

The Chairman's Message

Fellow Shareholders:

During 1983, a new combined system peak of 6,926,000 kilowatts was established on August 22, surpassing an earlier summer peak of 6,698,000 kilowatts set on July 21 and the previous year's peak of 6,602,000 kilowatts set on January 11, 1982. The new peak, including the North Carolina Eastern Municipal Power Agency's (Power Agency) requirements, represents a 4.9 percent increase over 1982.

A load forecast adopted in December projects an expected increase in peak demand for electricity of 2.6 percent annually through 1995. Our load forecast for 1995 has changed very little over the past three years, ranging between 9,206,000 and 9,386,000 kilowatts.

Construction expenditures in 1983 totaled $662 million. For 1984 we have adopted a construction budget of $716 million. For the three years 1984-1986, we estimate construction expenditures of $1.67 billion, excluding contributions by the Power Agency.

Company and Power Agency Complete Sale

During 1983, the Company completed the sale of undivided ownership interests in six of its generating units to the Power Agency. Including the Power Agency's share of output from those units, energy supplied by the total system to our customers and the Power Agency increased 5.1 percent over 1982.

The Power Agency bought 36 percent less energy from the Company. Nevertheless, the Company's sales electricity in 1983 we 30.9 billio. kilowa hours, up slightly fro 30.5 billion kilowa hours in 1982.

Operating revenu increased 7.1 perce to $1.65 billion and n income rose 5.3 pe cent to $239 million.

Earnings per sha of common stock we $3.21 compared wi $3.17 in 1982. The ave age number of shar outstanding increase 5.4 percent to mo than 60 million.

Highlights of 1983

	1983	1982	Percent Change
Operating Revenues	$1,647,183,000	$1,538,165,000	7.1
Net Income	$ 239,269,000	$ 227,147,000	5.3
Number Shares of Common Stock Outstanding (Year End)	62,485,000	58,835,000	6.2
Number Shares of Common Stock Outstanding (Average)	60,645,000	57,539,000	5.4
Earnings per Average Common Share Outstanding	$ 3.21	$ 3.17	1.3
Cash Dividends Paid per Common Share	$ 2.43	$ 2.40	1.3
Dividends Paid (Common and Preferred)	$ 190,963,000	$ 181,865,000	5.0
Kilowatt-Hour Sales (Thousands)	30,885,000	30,483,000	1.3
Company Capability Including Purchases (Kilowatts)	8,406,000	7,833,000	7.3
Maximum Hourly Load (Kilowatts)	6,622,000	5,965,000*	11.0
Total Utility Plant (Including Nuclear Fuel)	$5,604,880,000	$5,255,[illegible]15,000	6.6
Construction Expenditures	$ 661,637,000	$ 637,829,000	3.7
Customers (Year End)	796,000	772,000	3.1

*Excludes 637,000 kilowatts for Power Agency or participants prior to sales of facilities to Power Agency

Chairman/President Sherwood H. Smith, Jr. speaks at the dedication of the Mayo Plant.

arris Unit 2 Canceled

At year-end, the 00,000-kilowatt Unit 1 our Shearon Harris uclear plant was pproximately 83 per- ent complete. It is heduled to be opera- onal in 1986. We are moving ahead to complete it as rapidly and as economically as possible.

In December, the Company's Board of Directors approved the cancellation of Harris Unit 2. The project was about 4 percent complete and no major construction expenditures had been made during 1983. There were several reasons for the cancellation. In addition to a reduced rate of growth in demand for electricity, a primary reason was the substantial increase in costs due to continually changing and restrictive federal regulatory requirements. Under the circumstances, this change in our construction plan is in the best interests of both the Company and its customers.

ACRS Acts Favorably on Full Power Operating License for Harris

In its report to the Nuclear Regulatory Commission (NRC) in January 1984, the Advisory Committee on Reactor Safeguards (ACRS) reported that, upon satisfactory completion and resolution of outstanding issues, there is reasonable assurance that Harris Unit 1 can be operated at full power without undue risk to the health and safety of the public. In the opinion of the ACRS, all issues can be resolved.

Mayo Unit 1 Begins Operation

A major event during the year was the commercial operation of the 705,000-kilowatt Mayo Unit 1 in March. The coal-fired plant was formally dedicated in mid-June with North Carolina Governor James B. Hunt, Jr. citing the importance of the new facility to the area's growth and prosperity. Mayo Unit 2 is currently scheduled for service in 1991.

We continue to rely heavily on coal as our primary fuel for the generation of electricity. In 1983, about 73 percent of the Company's share of generation came from coal, 24 percent from nuclear, 2 percent from hydro and less than 1 percent from oil and natural gas.

Rate Increases Approved

Retail rate decisions in North Carolina and South Carolina in 1983 will result in $125.8 million in additional annual revenues. We will continue to seek rates that fully cover the cost of providing service. In February 1984, the Company filed a request for a 12.6 percent retail rate increase in North Carolina. A request for increased rates is also being filed in South Carolina.

Dividend Reinvestment Is Popular

Participation in our Automatic Dividend Reinvestment Plan continues to grow. At year-end, 40,415 shareholders were enrolled.

Our customers continue to respond positively to the Customer Stock Ownership Plan. Since its inception in 1981, more than 6,100 customers have purchased over 555,000 shares of common stock, representing an investment of more than $11 million.

1983 Marks 75th Year

On July 13, 1908, Carolina Power & Light Company was incorporated. At this time, the Company served 1,100 customers in Raleigh, Sanford and Jonesboro. In recognition of CP&L's 75 years of service, the Governors of North Carolina and South Carolina issued proclamations in July marking the Company's anniversary.

We look back on the past 75 years with a great deal of pride as the Company has grown to match the development of our service area. The accomplis
ments of our Compar
are the results of th
collective efforts of tho
sands of employees pa
and present and
those people—our shar
holders—who have i
vested their resourc
to provide a vital ser
ice that is now
much a part of o
daily lives.

As we look to th
future, we will continu
to explore new ar
innovative ways to me
the challenges of th
years to come and
serve our area ef
ciently and profitably

Sincerely,

Sherwood H. Smith, Jr.

Sherwood H. Smith, Jr.
Chairman/President

March 1, 1984

A time remembered

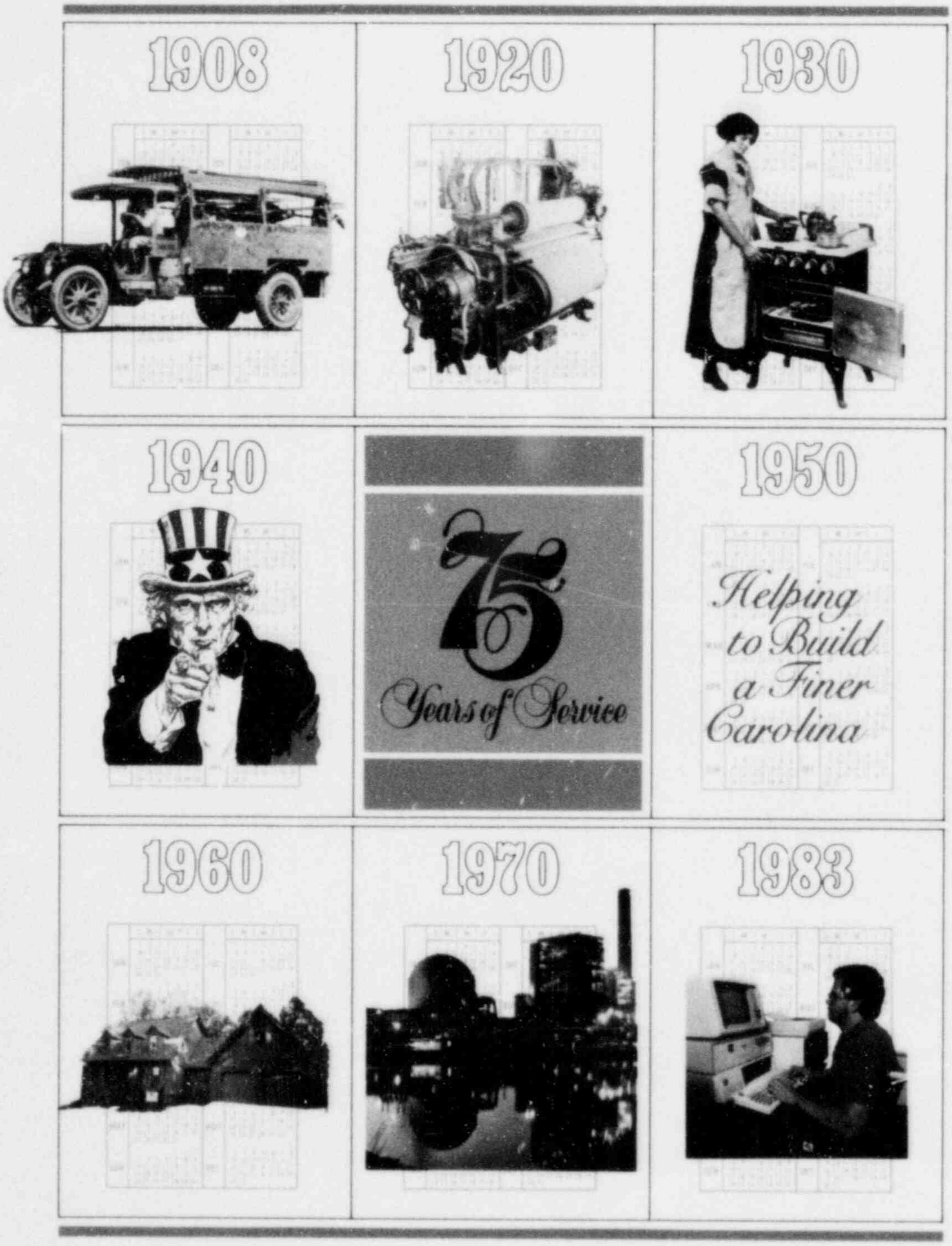
From lighter-than-air flight to manned space shuttles, from the telegraph to the telephone, from the typewriter to the word processor, from water power to nuclear power, Americans have witnessed incredible changes during the past 75 years.

It was the age of Edison and Einstein, of Salk and Sabin — a golden age of invention and discovery.

The leisurely pace of the turn-of-the century has been replaced by the increasingly rapid beat of a highly technological society. The invention of the light bulb and the spread in the uses of electricity helped revolutionize society and the manner of living.

Since CP&L began providing electricity in 1908, America has fought two world wars, placed a man on the moon, grown from a predominantly rural to an urban society and seen the advent of a vast array of microprocessors.

The availability of electricity in abundance has transformed our world. And electricity will continue to open new vistas in man's never-ending search for the better life.



The Year in Review

Energy Sales

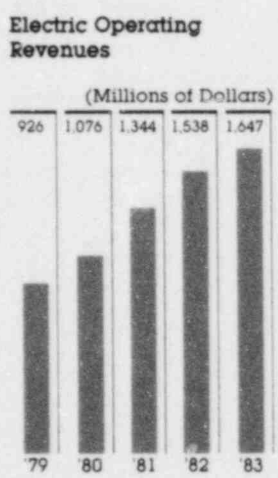
In 1983 the total of energy sales combined with the Power Agency's ownership share of output from jointly owned generating units increased by 5.1 percent. The Company's energy sales were 30.885 billion kilowatt-hours compared with 30.483 billion in 1982.

Residential sales increased 4.7 percent and industrial sales were up 7.2 percent. Sales to commercial customers increased 3.8 percent and to regular wholesale customers 4.7 percent.

Energy sales to the Power Agency and its participants decreased by 36.1 percent. The Power Agency receives electric generation directly from its jointly owned units and purchases its supplemental power from the Company.

Operating Revenues

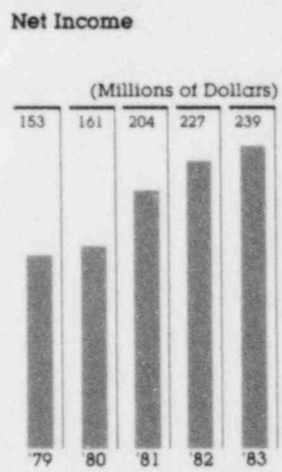
Operating revenues increased by $109 million, or 7.1 percent, to $1.65 billion. Of this increase, $71 million reflected general rate increases.



Operating Expenses

Operating expenses increased 7.2 percent to $1.38 billion. Significant increases in operating expenses included a $22 million increase in depreciation and amortization, primarily as a result of the start-up of Mayo Unit 1; a $28.8 million increase in income tax expense, reflecting an increase in pretax operating income; a $52.5 million increase in other operation expenses, principally related to possible losses associated with the Company's coal mining subsidiaries, and a $44.1 million increase in the cost of fuel.

These increases were offset somewhat by a $31.6 million decrease in purchased and interchange power, and a $30.1 million decrease in maintenance expenses, primarily for the nuclear generating units.

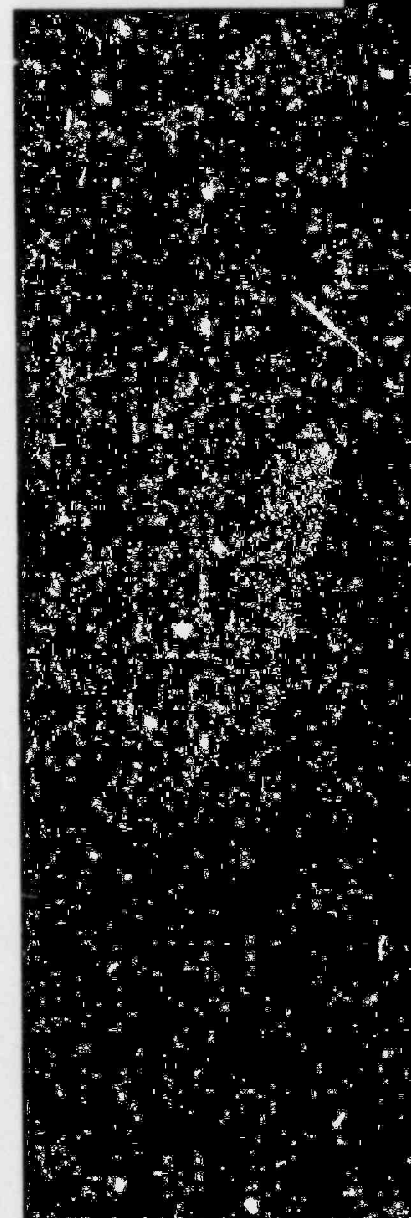


Net Income and Earnings

Net income for the year was $239 million, up 5.3 percent from 1982. Earnings per share were $3.21 compared with $3.17 in 1982. The annual dividend paid per share of common stock was $2.43. Effective with the November 1, 1983 dividend, the dividend rate increased to 63 cents a quarter or $2.52 on an annual basis.

Construction

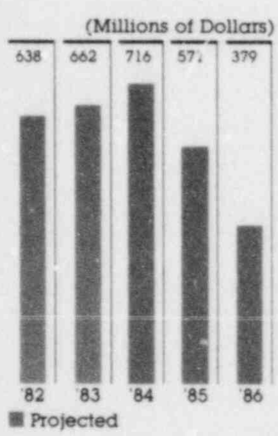
Company construction expenditures of $662 million in 1983 included $523 million for generating facilities, $59 million for transmission, and $80 million for distribution and general facilities.



In 1912 CP&L extended electric service by completing a 60-kv transmission line from Raleigh to Henderson. Dur[ing] the seventies, the Compan[y] constructed a 500-kv extra high voltage transmission line (top) to increase servi[ce] reliability.

During 1983, the Company generated internally from operations $398 million after dividends for its capital requirements, including construction. Of this amount, depreciation and amortization provided $169 million; retained earnings, $44 million; and deferral of income taxes and investment tax credits provided a net of $135 million.

Construction Expenditures



Financing

To supplement funds generated from operations and funds made available from the sale to the Power Agency, the Company obtained a net of $110.8 million from financing transactions in 1983.

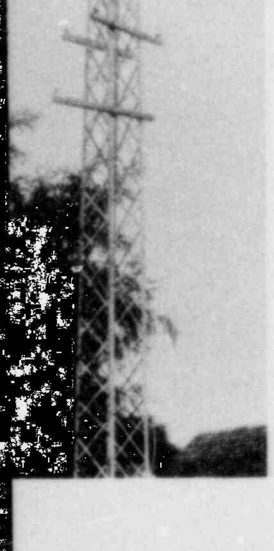
Those transactions included the sale and issuance of 3.65 million shares of common stock for $79.5 million through continuing plans for the sale of stock to employees, customers and shareholders; the withdrawal of $14.1 million of funds held by trustees from the sale in prior years of pollution control bonds; and the sale of $100 million of 12.875 percent First Mortgage Bonds due 2013.

The Company also issued $34.7 million principal amount of its First Mortgage Bonds, pollution control Series F, with proceeds of $32.1 million remaining with the trustee at December 31, 1983, pending expenditures.

In 1983, the Company received $79 million from the final closing in its sale to the Power Agency of undivided ownership interests in six CP&L generating units. The $154 million remaining in a trust at December 31, 1982 from the four closings in 1982 was utilized primarily in financing construction expenditures.

Capitalization

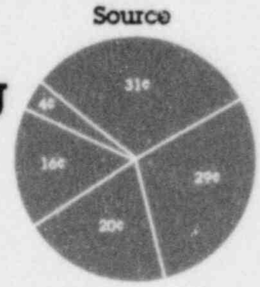
The Company's capitalization at year-end was more than $4 billion, consisting of 42.8 percent first mortgage bonds,



Operating Revenue Dollar

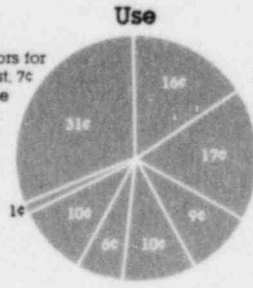
(Thousands of Dollars)

Source



31¢ Residential customers $518,246
29¢ Industrial customers $478,549
20¢ Commercial customers $325,468
16¢ Wholesale customers $262,890
4¢ Other electric operating revenues, $62,030
Total: $1,647,183

Use



31¢ Fuel, $516,510
16¢ Compensation to investors for use of their funds (interest, 7¢ preferred and preference stock, 2¢ common stock, 7¢), $263,956
17¢ Taxes, $276,738
9¢ Depreciation and amortization $148,342
10¢ Wages and employee benefits* $163,498
6¢ Maintenance (except employee wages), $94,898
10¢ Other operating expenses $164,658
1¢ Purchased and interchange power, net, $18,583
Total: $1,647,183

*Does not include $108,040,000 of wages and employee benefits for Company employees that were charged to Construction and other accounts.

39.5 percent common equity, 12.4 percent preferred and preference stock and 5.3 percent in other long term debt.

Revised Load Forecast

The Directors approved in December a load forecast that shows an expected growth in the peak demand for electricity of 2.6 percent annually through 1995, compared with 2.9 percent in last year's forecast.

The peak load forecast for 1995 has changed very little over the past three years, fluctuating between 9,206,000 and 9,386,000 kilowatts in the 1981, 1982 and 1983 forecasts. The expected rate of load growth reflects the anticipated success of the Company's conservation and load management programs in reducing electric demand.

The Company canceled Unit 2 of the Shearon Harris nuclear plant, which was scheduled for operation in 1990. Harris Unit 1 will remain on its present schedule with a projected completion date of 1986. Mayo Unit 2, a coal-fired unit, has been rescheduled from 1992 to 1991.

The Company's load forecast is evaluated on a continuing basis and the construction schedule is adjusted to reflect changes in load growth and in the Company's ability to raise capital.

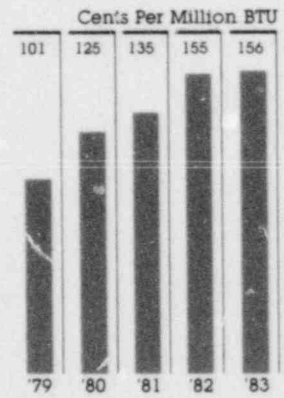
New Facilities

Unit 1 of the coal-fired Mayo Plant in Person County, North Carolina began commercial operation on March 1, 1983. Mayo Unit 2 is approximately 1 percent complete and is scheduled for commercial operation in 1991.

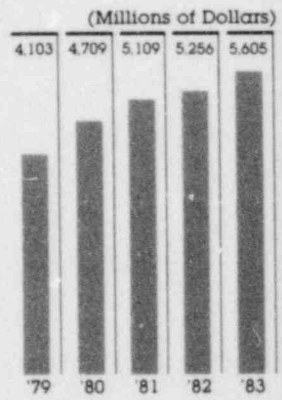
Construction of the 900,000-kilowatt Unit 1 of the Shearon Harris nuclear plant near Raleigh was 83 percent complete at year-end. The six major building structures required for Unit 1 are essentially complete, and extensive mechanical and electrical installation work is underway. The unit is scheduled for commercial service in 1986.

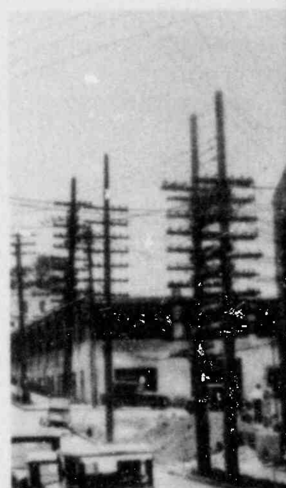
In January 1984, the Advisory Committee on Reactor Safety (ACRS) reported to the Nuclear Regulatory Commission (NRC) that upon satisfactory completion and resolution of outstanding issues, there is reasonable assurance that the Harris plant can be operated at full power without undue risk to the health and safety of the public. In the opinion of the ACRS, all issues can be resolved. The NRC requires ACRS review of

Fuel Expense
(All fuels as burned)



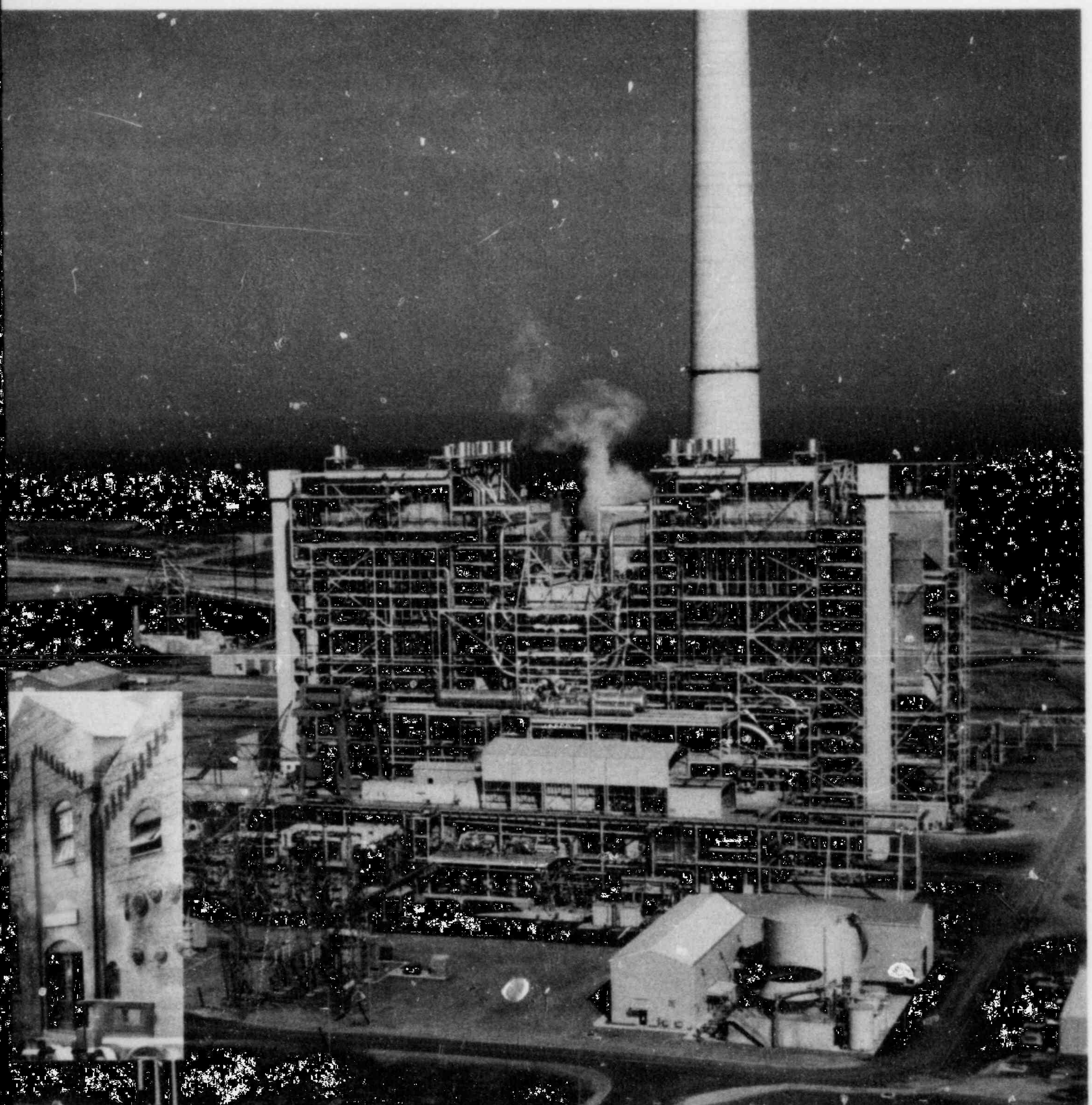
Total Utility Plant





Construction Schedule

Unit	Design Target Capacity	Type	In-Service Date
Harris 1	900,000 kilowatts	Nuclear	1986
Mayo 2	720,000 kilowatts	Coal	1991



The 1,000-kw Raleigh Steam Plant (inset) provided about a quarter of CP&L's generating capacity in 1908. Nearly 75 years later, the 705,000-kw coal-fired Mayo Plant became the Company's newest generating facility.

applications for operation of nuclear power plants.

Transmission lines authorized for construction in 1984 and following years include 177 miles of 500,000-volt line, 325 miles of 230,000-volt line, and 103 miles of 115,000-volt line.

Environmental Matters

In recent years, environmental protection has played an increasingly important role in the generation of electricity. Since 1968, the Company has invested more than $400 million in environmental protection equipment, $61.6 million of which was spent in 1983.

To ensure compliance with environmental regulations, the Company has a staff of scientists and specialists who collect, sample and analyze data, and perform chemical analyses to monitor the impact of generating facilities on aquatic and terrestrial ecosystems. A central laboratory is maintained at the Harris Energy and Environmental Center.

Historically, CP&L has taken the initiative to preserve natural areas and to promote wildlife in its service area. In 1983, the Company designated about 4,000 acres of land at the Shearon Harris nuclear plant site for wildlife management.

In July 1983, the Company completed installation of a new environmental system at the Brunswick Plant that is designed to reduce the effects of plant operation on marine life in the Cape Fear River. The system, which consists of a fish diversion structure, a holding pond and a sluiceway, protects the small marine life that enters the intake canal of the plant. Marine life is caught on mesh screens, then washed down a sluiceway into a holding pond, where it remains until returning to the river.

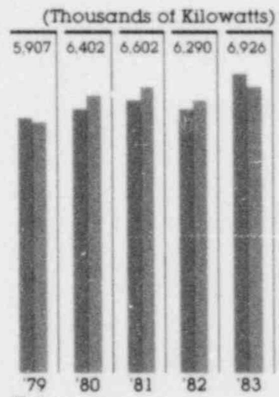
Operations

In 1983, total combined system energy requirements were 34.3 billion kilowatt-hours, including 1.5 billion kilowatt-hours of generation for the Power Agency from its portion of jointly owned units.

Total installed generating capacity was 8,750,000 kilowatts, including 494,200 kilowatts owned by the Power Agency. This reflected an increase in the capacity rating for Sutton Unit 3 from 385,000 kilowatts to 410,000 kilowatts and the addition of 705,000 kilowatts for Mayo Unit 1.

Coal-fired generating units at eight plants made up about

Combined System Peak Load*



Summer
Following Winter

*Includes NCEMPA load after 1981 for jointly-owned facilities.

60 percent of the system generating capacity; three nuclear units accounted for 26 percent; 33 internal combustion (IC) turbine generators that burn oil, natural gas or propane made up 12 percent; and four hydroelectric plants, 2 percent.

In 1983, coal provided 73 percent of the Company's share of electric generation, nuclear contributed 24 percent, water power 2 percent and other fuels less than 1 percent. The average fuel expense to generate a kilowatt-hour for nuclear plants was 0.5 cents; for coal-fired plants, 2 cents; and for IC turbines, 13.3 cents.

Coal consumption reache[d] a record high in 1983 when th[e] Company burned 10.1 millio[n] tons. The average delivere[d] price of coal in 1983 wa[s] $47.08 per ton, a decreas[e] of 1 percent from 1982.

Peak Loads

The annual peak for th[e] system, including the portio[n] owned by the Power Agenc[y], occurred on August 22, 198[3], when customer demand reache[d] a record of 6,926,000 kil[o]watts, a 4.9 percent increase ov[er] the 1982 peak of 6,602,000 kil[o]watts set on January 11, 1982.

Power Agency Agreement

The Power Agency has a[c]quired ownership interests [in] six of the Company's genera[t]ing units. The final closing wi[th] the Company was complete[d] in April 1983. The Power Agen[cy]'s ownership interests entit[le] it to receive the following shar[es] of generating capacity:

Brunswick 1	18.33%
Brunswick 2	18.33%
Roxboro 4	12.94%
Mayo 1	16.17%
Mayo 2	16.17%
Harris 1	16.17%

System Reliability

CP&L continued its parti[ci]pation as one of 27 utilities [in] the Southeastern Electric Reli[a]bility Council and in the sev[...]

ember Virginia-Carolinas eliability Group. Maintaining nd improving system reliabili- and cost-effectiveness for ember systems is the princi- l purpose for both groups. In pport of system and regional liability, the Company has 34 terconnections with neigh- oring systems.

uclear Fuel ipply and Storage

The Company has on hand has contracted for all raw aterials and nuclear fuel ser- ces to operate Robinson Unit hrough 1988, Brunswick Unit 1 through 1988, Brunswick Unit 2 through 1988 and Harris Unit 1 through 1987.

In January 1983, the President of the United States signed into law the Nuclear Waste Policy Act, which established a national policy for storage and disposal of nulcear waste. The law provides for Federal Interim Storage and Monitored Retrievable Storage, as well as Test and Evaluation and Repository programs.

In accordance with the law, the Company has entered into a contract with the Department of Energy (DOE) for disposal of spent nuclear fuel. The contract provides for Company payment to the DOE of the initial fee of one mill per kilowatt-hour of nuclear-generated electricity.

The law establishes 1998 as the date by which the DOE must fulfill its statutory and contractual obligations for the disposal of spent fuel. The Company is continuing to provide for spent fuel storage capacity within its own facilities on an interim basis.

In October 1983, the Company was authorized by the DOE, subject to successful negotiation of a cooperative agreement, to construct a demonstration facility for the dry storage of spent reactor fuel at the Company's H. B. Robinson Plant. This four-year research and development project, scheduled to begin in 1984, will be funded by the Company, the DOE and the Electric Power Research Institute.

Modifications to Nuclear Units

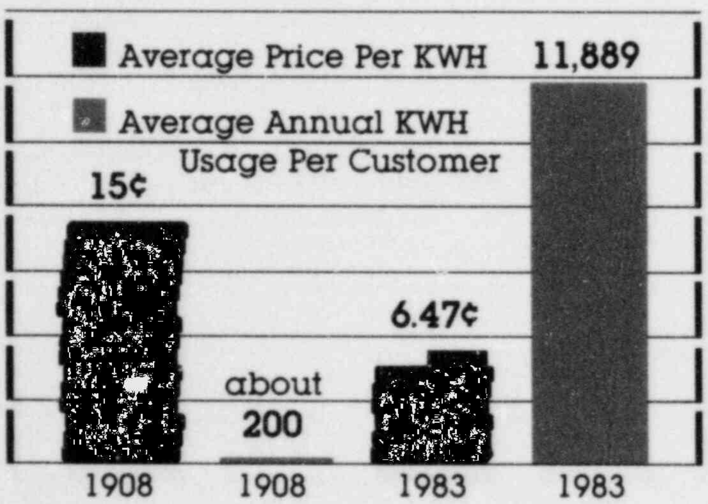
During 1983, the Company continued to implement changes to systems and procedures in response to Nuclear Regulatory Commission requirements and the Company's reliability improvement program. These major modifications resulted in additional capital expenditures for the Company of approximately $120.2 million in 1983.

Major modifications to Brunswick Unit 1 completed in 1983 included the replacement of the condenser tubes, changes in the augmented off-gas system, repairs of high pressure feedwater heaters, and completion of a recirculation pump and seal upgrade.

The first phase of torus modifications on both units at Brunswick was also completed. Final phases are scheduled for completion on Unit 2 in 1984 and Unit 1 in 1985.

Based on recent industry experience with intergranular stress corrosion cracking in boiling water recirculation piping, the Company has implemented a program to conduct inspections of the recirculation

Residential Service



The price per kilowatt-hour of electricity for a residential customer in 1983 was less than half of what it was in 1908. During the same period, household consumption increased dramatically.

piping at Brunswick. The Company is developing plans for replacement of the piping should it be found necessary.

Due to generic steam generator corrosion problems experienced at Robinson Unit 2, the Company is proceeding with plans to replace the steam generators. The Company has received the operating license amendment from the NRC authorizing the repair, and the replacement effort is underway.

Insurance for Nuclear Accidents

Under the Price-Anderson Act, total liability for a nuclear incident at December 31, 1983 was $580 million. Of this amount, $160 million is insured by conventional insurance pools. The remaining liability protection is provided by companies operating nuclear units. The Company's prorated maximum liability under this arrangement is presently $15 million per incident.

The Company is a member of Nuclear Mutual Limited, which provides insurance coverage for property damage to an insured's nuclear generating facilities. The Company is also a member of Nuclear Electric Insurance Limited, which provides property damage insurance in excess of that available from Nuclear Mutual Limited and coverage against incremental costs of replacement power resulting from prolonged accidental outages of members' generating units. The Company's property damage protection for each of its operating nuclear power plants is $935 million. The builders' risk protection for the plant under construction was $100 million. Maximum coverage for incremental costs of replacement power is $195 million per nuclear unit.

Rates

In 1983, the Company received approvals in North Carolina and South Carolina for retail rate increases and reached a settlement agreement with wholesale customers. These increases totaled $141.8 million in additional annual revenues.

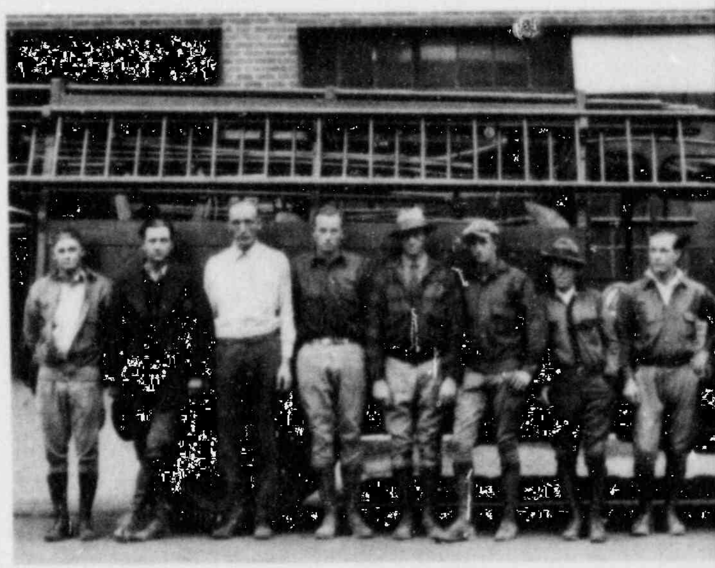
In September 1983, the North Carolina Utilities Commission approved new rate schedules which will provide $90.9 million in additional annual revenues. In October 1983, the South Carolina Public Service Commission approved new rates for South Carolina which will provide $34.9 million in additional annual revenues. In May 1983, the Federal Energy Regulatory Commission (FERC) approved a 1982 settlement agreement, which the Company had reached with its wholesale customers. This agreement permitted an annual increase of $16 million in wholesale rates. The rates were placed in effect, pending final FERC approval, on January 1, 1983.

Excluding special contract sales, about 69 percent of the Company's sales are regulated by the North Carolina Utilities Commission, 16 percent by the South Carolina Public Service Commission and 15 percent by the Federal Energy Regulatory Commission.

In other rate action, the North Carolina Supreme Court and the North Carolina Court of Appeals sent back to the North Carolina Utilities Commission two earlier retail rate cases and several fuel clause decisions for reconsideration. The courts concluded that fuel costs, including purchased power, should be considered in a general rate case, and that purchased power costs should not have been considered a part of the cost of fuel in fuel-cost-only proceedings. Reconsideration by the Commissio[n] is pending.

The Company filed on Sep[-]tember 26, 1983, an applica[-]tion with the FERC for [a] wholesale rate increase of 14[.] percent, or $30.7 million ann[u]ally. The increase was reques[t]ed to become effective subje[ct] to refund in two phases. Th[e] phase I increase of approx[i]mately $19 million, or 9 pe[r]cent, became effective Novem[-]ber 27, 1983. The phase [II] increase of $11.7 million, or 5

About 60 years separate these line crews. In the twenties, leather leggins, khaki pants and slouch hats were typical linemen's garb. The development of mechanized equipment has enabled today's crews to operate with fewer people.



ercent, was suspended for ve months to become effec- ve no earlier than April 27, 984. Any permanent increase the filed rates will follow earings scheduled for early mmer.

A final ruling by the FERC is xpected in 1984 on the Com- any's practice of charging for e cost of spent nuclear fuel orage and disposal. The RC disallowed the recovery these costs in a 1977 case nd denied the Company's re- uest for a rehearing. CP&L re- nded $15.3 million, including terest, in August 1982, and appealed the FERC's decision to the U.S. Court of Appeals for the District of Columbia Circuit. In August 1983, the court ruled that the FERC had not adequately stated the reasons for its action and sent the case back to the FERC for further consideration.

After numerous appeals to the FERC and to the courts, a FERC ruling requiring tax normalization in wholesale ratemaking was upheld. The court ruling left intact the Company's current method of tax normalization.

The Company has continued to develop new rates that encourage customer conservation and promote load management. In 1983, a time-of-use rate for large general service customers was made available, revised congeneration rates were approved, and a comparative billing program for residential and small general service customers was implemented. Under the comparative billing program, customer usage is computed under both the standard rate and the time-of-use rate; however, billing is based on the standard rate.

Research and Development

CP&L's research and development activities are carried out through the Electric Power Research Institute (EPRI) and through Company-sponsored programs and joint projects with the North Carolina Alternative Energy Corporation (NCAEC).

In 1983, the Company helped fund EPRI with a $4.8 million contribution. The research program carried out by EPRI develops new and improved technologies to help the utility industry meet energy needs in environmentally and economically acceptable ways. Near-term research and development projects (commercially available results within ten years) account for approximately 70 percent of EPRI's funding program.

Among other research projects, EPRI is conducting extensive study in the area of acid rain. The major objectives of EPRI's research are to identify utility contributions to the effects of acid rain and to provide sound scientific data that can be of use to regulators and legislators.

As part of its internal program, the Company has been involved with continuing research to develop distribution system automation. A field review now underway is demonstrating that high quality communications are feasible with power line carrier technology. A proposal for a large scale demonstration of distribution automation has been submitted to EPRI.

In its research program, the Company works with the NCAEC, a nonprofit organization underwritten by the electric suppliers in North Carolina, to carry out research related to energy conservation and load management.

Conservation and Load Management

An expanded conservation and load management effort aimed at reducing peak demand 1,750,000 kilowatts by 1995 has been underway since mid-1981. The Company's Conservation and Load Management (CLM) Department was established in 1982 to administer programs designed to meet the corporate goal.

During 1983, the department continued to develop strategies to pursue cost-effective energy programs that permit good service and support economic growth. Of the 36 programs identified for retail customers, 14 have been implemented while the remainder are in design or test stages.

CLM Programs in 1983

In the residential area, the Company expanded its appliance control program, which remotely controls residential air conditioners and water heaters during times of peak demand. Total participation in both air conditioner and water heater programs at the end of 1983 was more than 22,000.

Other residential programs included the 6% Home Energy Loan Program, which offers loans up to $600 at 6 percent interest for home energy improvements, a Community Energy Watch Program that in-

The homemaker of the early
venties began cooking the
ew-fangled electric way. Through
e years, advancements in electric
inges have made cooking
asier and more efficient.

volves the distribution and volunteer installation of weatherization materials; home energy analyses, and time-of-use comparative billing.

The Company's Common Sense Program, initiated in 1977 and 1978 to encourage increased energy efficiency in residences, certified more than 25,000 homes, 12,000 apartments and 6,900 manufactured homes by the end of 1983. During 1983, 65 percent of new residences in CP&L's service area were built to Common Sense standards.

In the commercial sector, the Company focused its 1983 efforts on program development. An audit test program was initiated to assist customers in evaluating energy needs. Time-of-use rates were requested by nearly 400 customers. Contacts were made with commercial customers who have the potential for using thermal storage applications.

In October 1983, the Company sponsored an Energy Management Seminar for architects and engineers to foster an exchange of information and ideas in energy management. Key design professionals from throughout North Carolina and South Carolina participated.

In the industrial sector, the Company emphasized cogeneration, development of small hydroelectric sites and energy management. The Company worked with private developers to encourage the reactivation of retired hydroelectric plants as additional sources of electricity. Four such projects were completed and brought on-line during 1983.

Under the cogeneration program, the Company continued to assist technically and cooperate with industrial and institutional customers and private entrepreneurs to encourage the development of economically feasible on-site power sources. Three new projects were completed and brought on-line during 1983, and three projects are under construction.

In addition, voluntary time-of-use rates became available to all industrial customers.

Customers

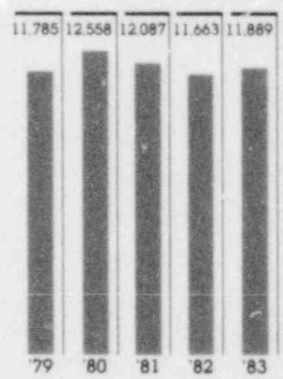
The Company served 796,000 retail customers at year-end, an increase of 3.1 percent over those served in 1982.

Residential

In 1983, the Company's 680,581 residential customers represented 85.5 percent of CP&L's total customers and accounted for 31.5 percent of operating revenues.

Average annual consumption per customer increased 1.9 percent from 11,663 kilowatt-hours in 1982 to 11,889 in 1983, primarily as a result of colder weather. The average annual residential bill increased from $722.26 in 1982 to $769.27 in 1983. The average price per kilowatt-hour increased from 6.19 cents in 1982 to 6.47 cents in 1983.

Average Annual Kilowatt-Hour Sales to Residential Customers

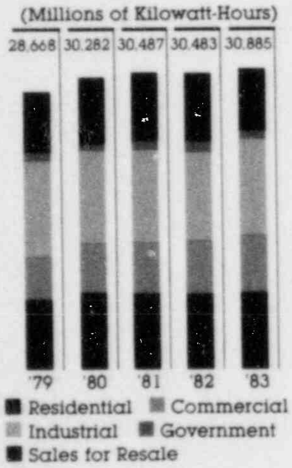


Commercial

At year-end, commercial customers totaled 110,341, an increase of about 4,000 over 1982. The commercial sector represented 13.9 percent of the Company's customers and produced 19.8 percent of operating revenues. In 1983, the average annual usage by commercial customers increased 1.2 percent, from 49,554 kilowatt-hours in 1982 to 50,125 in 1983.

Energy Sales by Classes Within Service Area

(Millions of Kilowatt-Hours)



Industrial

The Company gained 36 industrial customers during 1983, bringing the total served to 4,046. Energy usage by industrial customers was 10.2 billion kilowatt-hours, an increase of 7.2 percent for 1983.

During 1983, industries announced capital expenditures of $496 million for new and expanded industries in the Company's service area, which are expected to provide an estimated 9,000 new jobs, with an annual payroll of $127 million.

Resale and Military

CP&L provides electricity for resale to 18 electric membership corporations, four municipalities and one privately owned utility. In 1983, the wholesale customers accounted for 4.5 billion kilowatt-hours, or 14.4 percent of CP&L's total sales.

In addition, the Company serves five military bases that represent about 1 billion kilowatt-hours in energy sales.

Power Agency

The Company provides electricity to the North Carolina Eastern Municipal Power Agency for its participants. During 1983, CP&L sold 1.9 billion kilowatt-hours to the Power Agency in addition to the power supplied by the six generating units in which the Power Agency has joint ownership. These sales produced revenues of $71.9 million, and represented 6.1 percent of 1983 energy sales.

Project Share

In late 1982, the Company initiated a program called Project Share, a fund underwritten by CP&L, its employees and customers to help pay heating bills (oil, wood, gas or electric) for needy families in the Company's service area.

In 1983, about $298,000 was contributed on a matching basis to Project Share. The funds are distributed by the social services agencies in North Carolina and South Carolina.

As a result of this effort, the Company was one of 40 electric utilities in the country recognized by the White House for establishing a privately funded energy assistance program.

Human Resources

CP&L is an equal opportunity employer. Affirmative Action Plans, which are updated annually, include employment goals, outreach recruitment efforts, active involvement in community action programs and adherence to appropriate regulatory guidelines.

During 1983, the Company continued policies, practices and procedures to ensure equal opportunity for employees. Part of this effort involved training sessions for managers to emphasize the key role of the supervisor in fa employment practices.

Employee Development

To strengthen the Com pany's commitment to em ployee development, a ne Management Training Cente was established in Raleigh du ing the year. The facility pr vides an environment for Com pany-sponsored educationa and training programs. Durin 1983, 5,408 employees receive supervisory and general em ployee training to improve o the-job-performance.

Nearly 8,000 employee participated in a comprehe sive survey to determine at tudes on a number of job-relate subjects. The results indicated high level of employee sati faction. The survey provid the Company with a bench mark to identify and incorp rate many of the suggestio into overall corporate plannin

Distribution of Stock Ownership
(Common, Preferred and Preference Stock Combined)

	Shareholders	
	Number	Percent
The Carolinas	53,312	43
Elsewhere	70,176	57
Total	123,488	100

	Shares	
	Number	Percent
The Carolinas	18,619,827	27
Elsewhere	50,407,391	73
Total	69,027,218	100

afety Awards

CP&L employees in both orth Carolina and South Carolina keep the concept of safe- y a high priority. For the leventh consecutive year, the ompany earned the South- astern Electric Exchange ward (SEE) for the safest orking utility in its size category.

For the ninth consecutive ear, the Edison Electric Institute (EEI) presented CP&L its Safety Achievement Award. This award goes to a member company that compiles a commendable and lengthy time span between lost-time accidents. CP&L employees worked more than two million man-hours without a lost work day accident.

The North Carolina Department of Labor awarded CP&L a Certificate of Safety Achievement for the fifth consecutive year, and for the sixth consecutive year, a Special Award for working more than two million man-hours without a lost work day accident.

Ownership

The number of shares of common stock outstanding increased 6.2 percent during 1983 as a result of greater participation in the Automatic Dividend Reinvestment Plan, significant purchases under the Customer Stock Ownership Plan and shares issued under employee stock plans.

At year-end, there were 103,859 holders of common stock, 13,141 holders of preferred stock and 6,488 holders

This early scene of downtown Florence, S.C., is contrasted with today's modern shopping mall also located in Florence.

of preference stock, for a total of 123,488 shareholders. In addition, there are several thousand shareholders who own shares held by banks, brokers, investment trusts or nominees.

More than 43 percent of the shareholders of record live in North Carolina and South Carolina. The largest beneficial shareholder of record held less than 1 percent of the shares outstanding at year-end.

More than 87 percent of the eligible shares outstanding were represented in person or by proxy at the 1983 Annual Meeting.

Customer Stock Ownership Plan

Since the Company began offering the Customer Stock Ownership Plan in October 1981, more than 6,100 customers have enrolled. During 1983, over $6.7 million was invested by these customers and more than 309,000 shares of common stock were purchased. The plan is available to customers of CP&L who are at least 18 years old and legal residents of North Carolina or South Carolina. Participants enjoy such features as convenient monthly payments, 3 percent discount on purchases, and no commission or fees for purchases under the plan.

Automatic Dividend Reinvestment Plan

During 1983, the number of shareholders enrolled in the Automatic Dividend Reinvestment Plan increased significantly. At year-end, there were 40,415 shareholders participating compared with 34,893 at the end of 1982.

Under the plan, shareholders may reinvest dividends on common, preferred and preference stock toward the purchase of shares of CP&L common stock at 97 percent of the market value. Shares may also be acquired through optional cash payments at a 3 percent discount.

Tax Deferral on Reinvested Dividends

Under the provisions of the Economic Recovery Tax Act of 1981, most individual shareholders may elect to defer federal income taxes on dividends reinvested in CP&L common stock under the Automatic Dividend Reinvestment Plan. The

A typical CP&L district office in the forties and a new office of the eighties both emphasize customer service.

einvestment provisions of the Act allow individual shareholders to exclude from taxable income $750 ($1,500 on a joint return) of dividends reinvested in the plan in each of the four years 1982 through 1985.

Dividend Withholding Is Repealed

The provisions of the Tax Equity and Fiscal Responsibility Act of 1982 that would have required the Company and other dividend and interest paying corporations to withhold 10 percent of such payments have been repealed. However, under the Interest and Dividend Tax Compliance Act of 1983, the Company is required to withhold 20 percent of an individual's dividend payments if the shareholder fails to furnish the Company with a correct taxpayer identification number. The Company must also report to the Internal Revenue Service the sale of stock held under the dividend reinvestment plan.

Toll-free Telephone Service

The Company offers toll-free telephone lines as a convenience for shareholders. Shareholders in North Carolina may call 1-800-662-7232; outside North Carolina, 1-800-334-4374.

Management Changes

Two Vice Presidents Named

R. Thomas Dwyer, III, manager of the performance review and audit services department, and Cecil L. Goodnight, manager of the employee relations department, were elected vice presidents by the Board in May.

Mr. Dwyer has served in his present position since January 1981. He joined CP&L in 1978 as manager of audit services. He holds a master of business administration degree from the University of North Carolina at Chapel Hill and is a Certified Public Accountant.

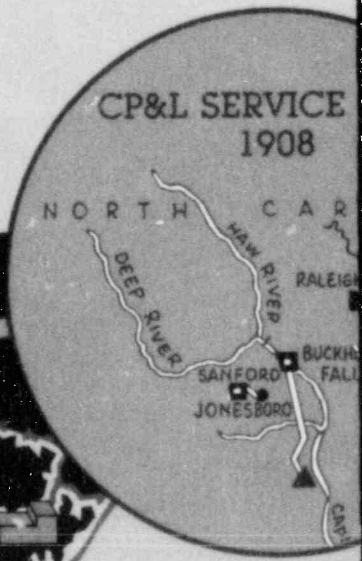
Mr. Goodnight joined CP&L in 1973 and held various personnel positions before being named department manager in 1980. He holds a bachelor's degree from La Verne College in California.

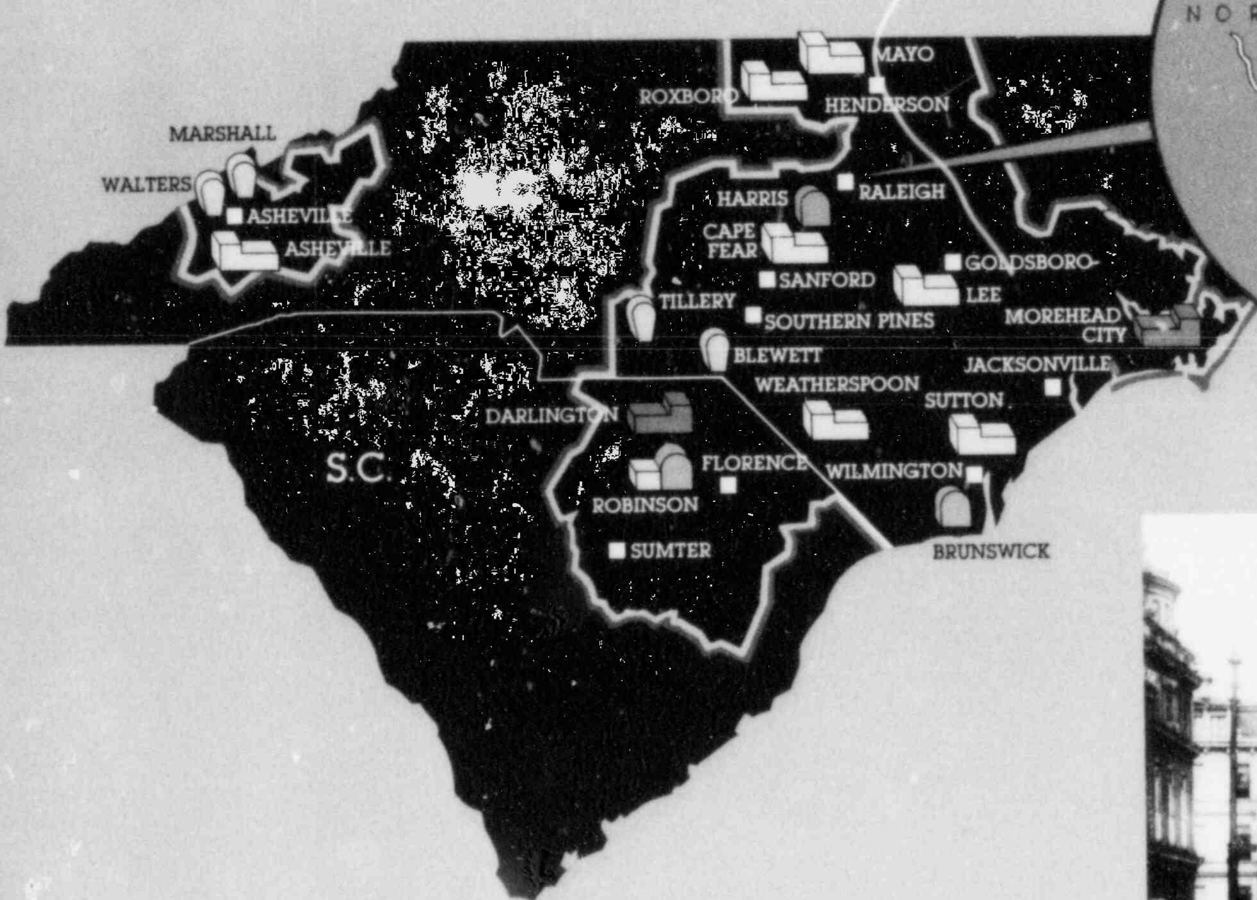
Tom Dwyer and Cecil Goodnight

Serving a Desirable Area

CP&L provides electric service to about 3 million people in a fast-growing Sun Belt area of some 30,000 square miles — almost half of North Carolina and one-fourth of South Carolina. Most customers live in uncongested small towns and active urban centers largely in the coastal plains, although the Company also serves portions of the piedmont and mountain sections of the two states.

CP&L's service area is attractive for its diversity of climate and geography. The mountains offer snow skiing, hiking and canoeing. The





Generating Plants:

Fossil — Fossil and Nuclear — Nuclear Site

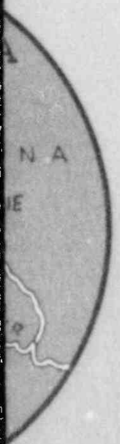
Nuclear — I.C. Turbine — Hydro

District Offices

ndhills area is often referred o as the golf capital of the vorld. The extensive coast line offers water sports and deep-ea fishing. Sports fans enjoy exciting Atlantic Coast Conference basketball.

The Company's headquarters are located in Raleigh, North Carolina, the system's largest city with a metropolitan population of 300,000. The area's three major universities and several smaller colleges provide extensive educational and cultural activities.

When the Company began operating in 1908, it served 1,100 customers in Raleigh, Sanford and Jonesboro. Today, CP&L serves 800,000 customers through five division, ten district and 42 area offices in the Carolinas. Electricity is produced at 15 generating plants.



The changing face of aleigh is reflected in its ain thoroughfare, ayetteville Street. The reet and its trolley acks have given way an attractive mall.

Management Report

The management of Carolina Power & Light Company is responsible for the information and representations contained in the financial statements and other sections of this Annual Report. The financial statements are prepared in conformity with generally accepted accounting principles and are consistent with other information in this report.

The Company has designed and maintains a system of internal accounting controls to ensure the reliability of the financial statements and to provide reasonable assurance that assets are safeguarded. This system is augmented by written policies and guidelines and a strong program of internal audit.

The Board of Directors pursues its oversight role for financial reporting and accounting through its audit committee. This committee, which is comprised entirely of outside directors, meets periodically with management and the internal auditors to review the work of each and to monitor the discharge by each of its responsibilities. The audit committee also meets periodically with the independent auditors, who have free access to the committee without management present, to discuss auditing, internal accounting control and financial reporting matters.

The independent auditors, Deloitte Haskins & Sells, are engaged to express an opinion on the Company's financial statements. Their opinion is based on procedures believed by them to be sufficient to provide reasonable assurance that the financial statements are not misleading and do not contain material errors.

Edward G. Lilly, Jr.
Chief Financial Officer

Paul S. Bradshaw
Chief Accounting Officer

Management's Comments on Financial Condition and Results of Operations

These comments are designed to analyze and discuss in greater detail the financial statements on pages 24-34 and the statistical review on pages 38-39. They should be considered in conjunction with the data appearing there.

Liquidity and Capital Resources

The Company's current construction program normally requires expenditures that are greater than funds generated internally. Sales of long-term securities and short-term borrowings are used to meet needs in excess of such internally generated funds.

Capital resources for 1981-83, summarized and restated from the "Statements of Source and Use of Financial Resources" to show dividends as a reduction in available resources, were provided as follows (in millions):

	Total	1983	1982	1981
Operations, less dividends	$ 912.6	**$398.1**	$241.9	$272.6
Sale of generating units	664.1	**79.3**	584.8	
Financings	818.1	**236.5**	136.7	444.9
Total	$2,394.8	**$713.9**	$963.4	$717.5

and utilized, as follows, for:

	Total	1983	1982	1981
Gross property and nuclear fuel additions	$1,948.0	**$708.6**	$654.7	$584.7
Retirement of long-term debt	346.5	**125.7**	160.0	60.8
Power Agency trust fund remaining		**(153.9)**	153.9	
Other working capital increase (decrease), etc	100.3	**33.5**	(5.2)	72.0
Total	$2,394.8	**$713.9**	$963.4	$717.5

The increase (decrease) in capital resources from operations, as compared with the preceding year, resulted from the following changes (in millions):

	1983	1982	1981
Net Income	**$ 12.1**	$ 23.6	$ 42.2
Dividends	**(11.5)**	(17.3)	(26.7)
Deferred income taxes and investment tax credits	**66.9**	(23.5)	52.5
Depreciation and amortization	**27.8**	(8.8)	24.2
Provision for coal mine investment losses	**49.9**		
Deferred income taxes credited to property accounts	**11.0**	(4.7)	(3.7)
Net increase (decrease) in resources from operations	**$156.2**	$ (30.7)	$ 88.5

The increase in resources from operations in 1983 resulted principally from (1) a return to a more normal level of deferred income taxes and investment tax credits from a year earlier when additional tax payments related to the sale of facilities were made which reduced the net deferred income tax provisions in 1982, (2) the net non-cash charges against income in 1983 related to provisions for possible coal mine investment losses offset by amortization of the gain from the sale of generating facilities and (3) increased depreciation and amortization charges consistent with increased plant in service and amortizable canceled project investment.

Internally generated funds from depreciation and amortization will increase significantly when the Harris Unit No. 1 is placed into commercial operation in 1986, and to the extent that the investment in the canceled Harris Unit No. 2 is amortized (see Note 6 to Financial Statements).

The relative amounts of resources obtained from financing activities have been as follows:

	1983	1982	1981
Common and preferred stocks	**33.9%**	39.4%	30.3%
First mortgage bonds	**71.4**	87.1	5.5
Long-term notes		44.1	18.0
Commercial paper backed by long-term credit facility	**(24.1)**		29.2
Nuclear fuel financing arrangements	**(4.4)**	4.2	9.4
Short-term transactions	**23.2**	(74.8)	7.6
	100.0%	100.0%	100.0%
Total financings were (in millions):	**$236.5**	$136.7	$444.9

During 1983, the amount of financing activities continued at a reduced level, compared to 1981 and previous years, because of the $153.9 million available from 1982 Power Agency sale closings plus an additional $79.3 million in 1983. Issuances of common stock under the various plans increased in 1983 (see Note 3 to Financial Statements) primarily due to the increased interest in the dividend reinvestment program and issuance of shares for the employees under the ESOP program.

Projected resources required for the next three years include (in millions):

	Total	1984	1985	1986
Construction expenditures	$1,666	$716	$571	$379
Nuclear fuel expenditures	278	101	68	109
Preferred stock redemptions	11	2	4	5
	$1,955	$819	$643	$493

The above estimates are subject to change as conditions change, e.g. unscheduled modifications or replacements at generating plants, both fossil and nuclear, could be required and would increase the projected requirements.

The cancellation of Harris Unit No. 2 has reduced significantly the capital requirements for 1985 and later years. Capital requirements for construction and nuclear fuel in 1984 and future years reflect significant reductions because of Power Agency's ownership interests. Increased inclusion by regulatory authorities of construction investment in the rate base reduces the amount of construction expenditures because less AFUDC is required to be capitalized (see Note 1(d) to Financial Statements).

The Company presently has on file with the Securities and Exchange Commission a shelf registration statement under which the Company can issue up to $150 million of additional First Mortgage Bonds (Shelf Bonds). The amount and timing of future sales of these and other securities will depend primarily upon market conditions and the needs of the Company.

The Company's ability to issue additional shares of preferred stock or First Mortgage Bonds is subject to earnings and other tests. Based upon unfunded property additions and retired bonds at December 31, 1983 and assuming the issuance of $150 million of Shelf Bonds, the Company could issue approximately $1.4 billion in additional First Mortgage Bonds. After the issuance of the Shelf Bonds (at an assumed rate of 13%) under the Company's Charter earnings test, at December 31, 1983, the Company could have issued approximately 3.6 million additional shares of preferred stock (at an assumed price of $100 per share and $11.00 annual dividend rate). The 8 million authorized, but unissued, preference stock shares are not subject to an earnings test.

The Company currently expects to elect by June 30, 1985 to defer payment of the $88 million accrued liability for nuclear fuel disposal costs (see Note 8(e) to Financial Statements). The Company has the option until June of 1985 to pay the accrued amount at that time without interest, to elect to pay in quarterly installments with interest over a future ten-year period, or to pay in one lump sum with interest in the late 1990s.

Short-term liquidity: Customer receivables on the books at year-end represent an average of less than 20 days billings. At December 31, 1983, the Company had firm, unused bank lines of credit totaling $206.7 million and a $130 million irrevocable revolving credit facility. These facilities serve as back-up to outstanding commercial paper and $57 million of pollution control First Mortgage Bonds that are redeemable annually at the option of the holder (annual tender bonds). In connection with the annual tender bonds, the Company has contracted for remarketing in the event of tender for repurchase. The obligations supported by the $130 million revolving credit facility are classified as long-term debt on the balance sheet. Proceeds from the issuance of the Series F pollution control bonds totaling $32.1 million are held in trust pending use for qualifying expenditures.

At December 31, 1983, the Company had unused investment tax credits of $109 million and a tax loss carryforward of approximately $81 million that can be used to reduce federal income tax payments in 1984, or later years if not used in 1984.

Results of Operations

Operating revenues increased during 1983 and 1982 principally because of (1) general rate increases that produced $70.6 million more in 1983 as compared with 1982 and $140.5 million more in 1982 than in 1981, and (2) fuel cost adjustment billings that decreased $21.0 million in 1983 from 1982 levels while increasing $34.3 million in 1982 from severely depressed 1981 levels, and (3) a 1.3 percent overall increase in energy sales in 1983. The 1983 increases in energy sales include the net effect of a 5.4 percent increase in retail and regular wholesale customer energy sales and a 36.1 percent decrease in Power Agency related sales, which fluctuate with output levels of the jointly owned generating units as well as customer demands.

Operating expenses reflect increased costs of fuel for greater generation of electricity in 1983 to serve increased customer needs and to replace a portion of the more expensive purchased and interchange power costs that occurred in the prior year. Generation from the coal-fired Mayo Unit No. 1 that was placed into commercial operation on March 1, 1983 was responsible for a considerable portion of the increased output. Also, the Company experienced increased nuclear power plant availability in 1983, as compared with 1982. The provision in 1983 for possible coal mine investment losses of $49.9 million increased operating expenses and is related to investment in coal mining subsidiaries (see Note 2 to Financial Statements).

Maintenance expense, which declined in 1983, was reduced by a one-time credit of $15.7 million in order to capitalize certain replacements of property items at generating plants that were expensed in prior years, principally, 1982; and it also decreased overall at generating plants from levels in recent years. Generally, operating expenses increased, especially depreciation, due to Mayo Unit No. 1 being placed into commercial operation.

Other income declined due to a decrease in the allowance for other funds used during construction, reflecting reduced investments in construction, principally because the Mayo Unit No. 1 was placed into commercial operation. Other income also declined because of expenses of operation of the Company's coal mining subsidiaries. Income tax credits decreased principally because of lower capitalized interest charges. Offsetting these decreases is amortization of a portion of the gain from sale of generating facilities to the Power Agency.

Interest charges reflect lower short-term and variable long-term interest rates in 1982 and 1983. The allowance for borrowed funds used during construction, net of deferred income tax effects, decreased in 1983 because of reduced investments in construction. Furthermore, the inclusion of construction investments in the rate base decreased the allowance for borrowed and other funds by $39.5 million in 1983, $43.4 million in 1982 and $21.9 million in 1981 (see Note 1(d) to Financial Statements).

Net income and earnings: In summary, while earnings for 1983, 1982 and 1981 have increased from year to year, earnings have been adversely affected by continuing inflation and high levels of operation expenses and other cost increases not fully reflected in approved revenue levels. In 1983, lower interest rates and levels of inflation had less adverse impact on earnings than in recent years. The charge to operations for possible investment losses applicable to the coal mine subsidiaries adversely affected 1983 results. Increased energy sales because of colder weather and an upturn in economic activity contributed favorably to earnings in 1983. The quality of earnings has improved somewhat because of less AFUDC and more compensating revenue, as increased amounts of construction investment have been allowed in the rate base. Earnings per share of common stock have been adversely affected by the increased number of shares outstanding.

Impacts of Inflation

See Supplemental Inflation Adjusted Data on pp. 35-37 for the estimated effects of changing prices on income, on the basis prescribed by the Financial Accounting Standards Board.

Balance Sheets

Carolina Power & Light Company December 31, 1983 and 1982

Assets	1983	1982
	(In Thousands)	
Electric Utility Plant:		
Electric utility plant other than nuclear fuel:		
In service	$3,629,625	$3,019,141
Held for future use	12,902	10,350
Construction work in progress	1,697,551	1,994,906
Total	5,340,078	5,024,397
Less accumulated depreciation	884,250	792,013
Net	4,455,828	4,232,384
Nuclear fuel	264,802	231,518
Less accumulated amortization	149,424	131,280
Net	115,378	100,238
Electric utility plant, net	4,571,206	4,332,622
Current Assets:		
Cash and temporary cash investments	9,214	8,028
Accounts receivable, net	97,651	75,140
Power Agency Trust Fund		153,891
Materials and supplies:		
Fuel	101,893	121,896
Other	25,338	29,495
Deferred fuel cost	6,186	5,070
Current portion of deferred income taxes	16,967	16,948
Prepayments, etc.	9,162	20,636
Total current assets	266,411	431,104
Other Assets:		
Unamortized canceled project costs:		
Harris Unit No. 2 (Note 6)	263,733	
Harris Units Nos. 3 and 4 (Note 8[f])	121,460	124,587
Unrecovered nuclear fuel disposal costs (Note 8[e])	29,267	
Investment in coal-mining subsidiaries (Note 2)	2	19,620
Miscellaneous other property and investments	22,348	18,560
Unamortized debt expense	3,467	3,230
Other deferred debits	15,712	21,232
Total other assets	455,989	187,229
Total	$5,293,606	$4,950,955

See notes to financial statements.

Balance Sheets

Carolina Power & Light Company December 31, 1983 and 1982

Liabilities	1983	1982
	(In Thousands)	
Capitalization (see Schedules of Capitalization):		
Common stock	$1,151,323	$1,071,863
Common stock subscribed	2,205	1,528
Retained earnings	432,913	388,774
Preference stock	47,900	47,900
Preferred stock—redemption not required	238,118	238,118
Preferred stock—redemption required, net	214,785	214,743
Long-term debt (excluding current maturities), net	1,909,823	1,891,702
Total capitalization (excluding current maturities of long-term debt)	3,997,067	3,854,628
Current Liabilities:		
Long-term debt due within one year	21,849	64,122
Notes payable:		
Bank demand notes		13,000
Other (principally commercial paper)	82,703	19,210
Accounts payable:		
Construction contract retentions	5,370	13,725
Other	126,055	109,839
Customers' deposits	7,905	7,025
Taxes accrued	41,782	68,467
Interest accrued	42,378	41,491
Dividends declared	58,833	54,769
Other	4,319	4,005
Total current liabilities	391,194	395,653
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes:		
Harris Units Nos. 2, 3 and 4	134,702	35,885
Gain on sale of facilities (Note 7)	(98,125)	(94,080)
Other, net	494,624	447,926
Total accumulated deferred income taxes	531,201	389,731
Accumulated deferred investment tax credits	174,112	180,700
Unamortized gain on sale of facilities (Note 7)	128,104	117,348
Other	71,928	12,895
Total deferred credits and other liabilities	905,345	700,674
Commitments and Contingencies (Notes 2, 6, 7 and 8)		
Total	$5,293,606	$4,950,955

See notes to financial statements.

Statements of Income

Carolina Power & Light Company For the Years Ended December 31,

	1983	1982	1981
	(In Thousands Except Earnings Per Share)		
Operating Revenues (Note 9)	$1,647,183	$1,538,165	$1,343,558
Operating Expenses:			
Operation:			
Fuel for generation	517,625	473,509	459,591
Deferred fuel costs	(1,115)	1,423	523
Purchased and interchange power, net	18,583	50,226	19,388
Other (Note 2)	285,671	233,147	174,084
Maintenance	137,383	167,458	125,876
Depreciation and amortization (Note 1)	148,342	126,355	110,409
Taxes other than on income	114,295	104,300	97,288
Income tax expense (Note 5)	162,443	133,622	118,996
Total operating expenses	1,383,227	1,290,040	1,106,155
Operating Income	263,956	248,125	237,403
Other Income:			
Allowance for other funds used during construction	94,927	98,353	92,508
Income tax credits (Note 5)	31,078	38,472	35,846
Amortized gain on sale of facilities (Note 7)	11,422		
Other income (deductions), net (Note 2)	(4,945)	13,919	8,593
Total other income	132,482	150,744	136,947
Income Before Interest Charges	396,438	398,869	374,350
Interest Charges:			
Long-term debt	171,448	180,986	177,981
Other	17,551	34,001	31,201
Allowance for borrowed funds used during construction-credit (Note 5)	(31,830)	(43,265)	(38,429)
Net interest charges	157,169	171,722	170,753
Net Income	239,269	227,147	203,597
Preferred and Preference Stock Dividend Requirements	44,605	44,605	42,660
Earnings for Common Stock	$ 194,664	$ 182,542	$ 160,937
Average Common Shares Outstanding	60,645	57,539	52,554
Earnings Per Common Share	$ 3.21	$ 3.17	$ 3.06

See notes to financial statements.

Statements of Retained Earnings

For the Years Ended December 31,

	1983	1982	1981
	(In Thousands)		
Balance at Beginning of Year	$ 388,774	$ 345,353	$ 309,819
Net Income	239,269	227,147	203,597
Total	628,043	572,500	513,416
Deduct:			
Cash dividends declared:			
Preferred and Preference Stock at stated rates (Note 1)	44,605	44,605	44,060
Common Stock (at annual rate of $2.46 a share in 1983, $2.40 in 1982 and $2.32 in 1981)	150,423	138,878	123,578
Total cash dividends declared	195,028	183,483	167,638
Capital stock discount and expense	102	243	425
Total deductions	195,130	183,726	168,063
Balance at End of Year	$ 432,913	$ 388,774	$ 345,353

See notes to financial statements.

Statements of Source and Use of Financial Resources

Carolina Power & Light Company For the Years Ended December 31,

	1983	1982	1981
		(In Thousands)	
Source of Financial Resources:			
Current resources provided from operations:			
Net income	$ 239,269	$ 227,147	$ 203,597
Items not requiring (providing) current resources:			
Depreciation and amortization	180,565	141,334	150,105
Amortized gain on sale of facilities	(11,422)		
Provision for possible coal-mine investment losses	49,868		
Noncurrent deferred income taxes, net	172,341	10,391	150,940
Investment tax credit adjustments, net	(6,589)	88,493	(28,569)
Other funds portion of AFUDC	(94,927)	(98,353)	(92,508)
Total current resources provided from operations	529,105	369,012	383,565
Sale of generating facilities	79,301	584,801	
Total current resources	608,406	953,813	383,565
Additions to plant accounts representing capitalization of other portion, less deferred income taxes on borrowed funds portion of AFUDC	64,056	56,405	55,231
Total resources provided excluding financings	672,462	1,010,218	438,796
Financings:			
First mortgage bonds	168,767	119,038	24,248
Preferred stock			39,458
Common stock—Public offerings			59,616
Common stock—Plans (Note 3)	80,077	53,852	35,931
Other long-term notes	42	60,270	80,000
Commercial paper backed by long-term credit facility	(57,015)		130,000
Nuclear fuel trust and lease obligations	(10,409)	5,731	41,954
Decrease in temporary cash investments plus increase in short-term notes payable	54,993	(102,195)	33,705
Total resources provided from financings	236,455	136,696	444,912
Total	$ 908,917	$1,146,914	$ 883,708
Use of Financial Resources:			
Gross property additions, excluding nuclear fuel*	$ 660,130	$ 638,284	$ 548,508
Nuclear fuel additions*	48,488	16,450	36,223
Canceled projects expenditures	20,710	15,355	
Dividends for the year	195,028	183,483	166,238
Repayment of first mortgage bonds	123,346	20,000	15,000
Repayment of other long-term debt	2,333	140,064	
Repayment of nuclear fuel lease obligation			45,827
Net increase (decrease) in the following working capital components:			
Power Agency trust fund	(153,891)	153,891	
Accounts receivable, net	22,511	4,284	8,019
Materials and supplies	(24,160)	13,968	19,930
Accounts payable	(7,861)	(10,482)	56,943
Reserve for refund of revenues	499	24,094	(15,799)
Other, net	15,389	(25,687)	(11,002)
Miscellaneous, net	6,395	(26,790)	14,821
Total	$ 908,917	$1,146,914	$ 883,708

*Includes amounts capitalized as allowance for funds used during construction, net of related deferred income taxes.

See notes to financial statements.

Schedules of Capitalization

Carolina Power & Light Company December 31, 1983 and 1982

	1983	1982
	(In Thousands)	
COMMON STOCK EQUITY (Note 3):		
Common stock without par value, authorized, 100,000,000 shares:		
Outstanding 62,484,959 shares at December 31, 1983 and 58,835,176 shares at December 31, 1982	**$1,151,323**	$1,071,863
Subscribed	**2,205**	1,528
Retained earnings, limited in payment as dividends under certain circumstances under the Company's charter; however, none restricted at December 31, 1983	**432,913**	388,774
Total common stock equity	**$1,586,441**	$1,462,165

PREFERENCE AND PREFERRED STOCK, without par value, cumulative (Note 3):

	At December 31, 1983			
	Redemption Price	Shares Outstanding	1983	1982
Preference stock, authorized 10,000,000 shares (entitled to $25 a share plus accumulated dividends in the event of liquidation, in preference only to common stock)—				
$2.675 Series A	$ 26.50	2,000,000	**$ 47,900**	$ 47,900
Preferred stock (a)—redemption not required:				
$5 Preferred Stock—authorized, 300,000 shares	$110.00	237,259	**$ 24,376**	$ 24,376
Serial Preferred Stock(b):				
$4.20 Series	102.00	100,000	**10,000**	10,000
5.44 Series	101.00	250,000	**25,000**	25,000
9.10 Series	103.00	300,000	**30,000**	30,000
7.95 Series	104.00	350,000	**35,000**	35,000
7.72 Series	104.00	500,000	**49,425**	49,425
8.48 Series	105.00	650,000	**64,317**	64,317
Total—redemption not required		2,387,259	**$ 238,118**	$ 238,118
Preferred stock (a)—redemption required (c):				
Serial Preferred Stock (b)—				
$11.16 Series	$111.16	400,000	**$ 40,000**	$ 40,000
14.00 Series	114.00	400,000	**40,000**	40,000
Preferred Stock A, authorized, 5,000,000 shares:				
$7.45 Series	104.00	500,000	**50,000**	50,000
8.75 Series	107.23	500,000	**50,000**	50,000
9.25 Series	104.50	180,000	**18,000**	18,000
9.00 Series	(c)	175,000	**17,500**	17,500
Unamortized discount			**(715)**	(757)
Total—redemption required		2,155,000	**$ 214,785**	$ 214,743

(a) Entitled to $100 a share plus accumulated dividends in the event of liquidation.
(b) Authorized, 20,000,000 shares in total.
(c) Minimum sinking fund requirements (at $100 per share plus accumulated dividends) commence in 1984 for the $7.45 Series, at 20,000 shares per year; in 1985 for the $8.75 Series at 20,000 shares per year and increasing in the year 2000 to 40,000 shares annually; in 1986 for the $11.16 Series at 12,000 shares per year; in 1987 for the $14.00 Series at 16,000 shares per year; and in 1990, for the $9.00 Series, all 175,000 shares are to be redeemed. With respect to the $9.25 Series, the Company must offer to redeem annually, on March 1 of each year beginning in 1988, any or all shares outstanding. Minimum sinking fund requirements for the next five years aggregate: 1984, $2,000,000; 1985, $4,000,000; 1986, $5,200,000; 1987, $6,800,000 and 1988, $6,800,000.

See notes to financial statements.

	1983	1982
	(In Thousands)	
LONG-TERM DEBT (a):		
First mortgage bonds-principal amounts:		
Other than Pollution Control Series:		
Maturing 1983 through 1993:		
11 %, due April 15, 1984 (redeemed 10-15-83)		$ 67,346
14⅛%, due April 1, 1987	$ 125,000	125,000
4⅛%, due March 1, 1988	20,000	20,000
4⅞%, due April 1, 1990	25,000	25,000
4½%, due November 1, 1991	25,000	25,000
11⅜%, due December 1, 1992	100,000	100,000
Maturing 1994 through 1998—4½% to 6⅞%	140,000	140,000
Maturing 1999 through 2003—7⅜ to 8¾%	525,000	525,000
Maturing 2004 through 2008—8½% to 9¾%	325,000	325,000
Maturing 2009 through 2013—10½% to 12⅞%	325,000	225,000
Pollution Control Series:		
A. 8 %, due 2001-2009 (principal amount less proceeds held by Trustee: 1982, $1,900)	63,000	61,100
B. 7¼% due 10-1-83 (principal amount less proceeds held by Trustee: 1982, $12,227)		37,773
C. 7¼% due 10-1-83		6,000
D. (5.65% to 4/1/84) due 4-1-2009	48,485(b)	
E. (5.65% to 4/1/84) due 4-1-2009	5,970(b)	
F. (7.00% to 11/1/84) due 11-1-2010 (principal amount less proceeds held by Trustee: 1983, $32,140)	2,560(b)	
Total first mortage bonds-principal amounts	1,730,015	1,682,219
Other long-term debt:		
Nuclear fuel trust obligations (variable rates: 10.47% average effective interest cost at 12-31-83; 9.56% at 12-31-82)	80,215	90,624
16½% Guaranteed Notes (Finance N.V.) due 2-15-89 (Note 1 [b])	60,000	60,000
Carolina Pipeline (Variable interest rate - 11.5% at 12-31-82)		2,333
Commercial paper backed by long-term credit facility to 9-24-86 (9.70% average effective interest rate at 12-31-83; 8.66% at 12-31-82)	72,985	130,000
Miscellaneous promissory notes	107	66
Total long-term debt, principal amounts	1,943,322	1,965,242
Unamortized discount and premium, net	(11,650)	(9,418)
Total long-term debt, including current maturities	1,931,672	1,955,824
Less long-term debt due within one year:		
Nuclear fuel trust obligations	21,849	19,882
7¼% Pollution Control Bonds, due 10-1-83		43,773
Carolina Pipeline due 10-1-83		467
Total long-term debt, excluding current maturities	$1,909,823	$1,891,702
TOTAL CAPITALIZATION (excluding current maturities of long-term debt)	$3,997,067	$3,854,628

(a) Long-term debt maturities for the next five years, including estimated amounts under continuous nuclear fuel financing arrangements for which repayments of present obligations are based on energy produced, are (in thousands):

	1984	1985	1986	1987	1988
First mortgage bonds				$125,000	$20,000
Nuclear fuel	$21,849	$18,488	$ 20,877	10,507	3,556
Long-term credit facility obligations			130,000		
Totals	$21,849	$18,488	$150,877	$135,507	$23,556

(b) Redeemable annually at the option of the holder—backed up by a portion of the long-term credit facility of $130,000,000.

See notes to financial statements.

Notes to Financial Statements

1. **Summary of Significant Accounting Policies**

(a) System of Accounts. The accounting records of the Company are maintained as prescribed in uniform systems of accounts of the Federal Energy Regulatory Commission (FERC) and the regulatory commissions of North Carolina and South Carolina.

(b) Subsidiaries. The Company's financial statements reflect consolidation of its wholly-owned foreign financing subsidiary, Carolina Power & Light Finance N.V., which in 1982 was organized and issued $60,000,000 principal amount of 16½% Guaranteed Notes. See Note 2 for information on the coal-mining subsidiaries.

(c) Electric Utility Plant. The cost of additions, including replacements of units of property and betterments, is charged to utility plant. Maintenance and repairs of property, and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense. The cost of units of property replaced or renewed or otherwise retired, plus removal or disposal costs, less salvage, is charged to accumulated depreciation. Electric utility plant, other than nuclear fuel, is subject to the lien of the Company's mortgage. Nuclear fuel is pledged, or subject to be pledged, as collateral for nuclear fuel financing arrangements.

(d) Allowance for Funds Used During Construction (AFUDC). As prescribed in regulatory uniform systems of accounts, an allowance for the cost of borrowed and other funds used to finance electric utility plant construction, less applicable income taxes, is charged to cost of plant. Regulatory authorities consider the inclusion of these recognized costs as appropriate for the purpose of establishing rates for the Company's utility charges to customers over the service lives of the property. The other portion of AFUDC is credited to other income, the borrowed funds portion is credited to interest charges and the deferred income tax provision is reflected as a reduction in AFUDC-borrowed funds. The composite, net-of-tax AFUDC rate was approximately 9.3 percent in 1983 and 1982 and 8.8 percent in 1981.

Certain construction-work-in-progress expenditures (totaling $662,570,000, $412,535,000, $405,419,000 and $229,590,000 at December 31, 1983, 1982, 1981 and 1980, respectively) are included in the rate base for ratemaking purposes. AFUDC is not capitalized (charged to the cost of plant) on such expenditures.

(e) Depreciation and Amortization. Depreciation of utility plant, other than nuclear fuel, for financial reporting purposes is computed on the straight-line method based on estimated remaining useful lives, adjusted for estimated net salvage or disposal costs, and charged principally to depreciation expense. Depreciation provisions, as a percent of average depreciable property other than nuclear fuel, approximated 3.8 percent in 1983 and 1982 and 3.6 percent in 1981. Depreciation rates are reviewed periodically and changes in estimates (including the costs to dismantle or decontaminate nuclear generating plants) are made, as appropriate, on a prospective basis.

Allowable depreciation rates for wholesale ratemaking purposes have been different from those regularly used by the Company and allowed by other ratemaking jurisdictions; therefore, the Company recorded lower depreciation provisions solely applicable to wholesale operations ($1,947,000 less for 1983, $1,527,000 less for 1982 and $3,383,000 less for 1981).

Amortization of nuclear fuel costs (1983, $30,594,000; 1982, $13,536,000; 1981, $38,784,000), including disposal costs through April 6, 1983, is computed on the unit of production method and charged to fuel expense. The amortization charges for disposal costs totaled, for 1983 through April 6, $3,650,000; for 1982, $7,684,000 less a wholesale revenue refund related reduction of $14,313,000 applicable to the years 1977-1982; and for 1981, $10,064,000. Nuclear fuel disposal costs are paid quarterly for nuclear generation after April 6, 1983. (See Note 8(e)).

(f) Revenues. Customers' meters are read and bills are rendered on a cycle basis. Revenues are recorded when billed, as is the customary practice in the industry.

(g) Deferred Fuel Costs. The Company's rates in all three of its regulatory jurisdictions are adjustable for fluctuations in fuel costs. For South Carolina retail operations, the Company defers the difference between fuel costs incurred and the related customer billings and periodically adjusts rates to reflect this difference. For wholesale operations, the Company adopted a similar procedure effective January 1982. For North Carolina retail operations, pursuant to a June 1982 amendment to North Carolina utilities law, the fuel cost component of rates reflects estimated fuel expense for the period that the rates will be in effect and may be adjusted once in every twelve months in fuel-cost-only proceedings. In addition, fuel costs may be considered in general rate case proceedings.

Effective for service rendered on and after September 19, 1983 the North Carolina Utilities Commission approved a general rate increase that included a base fuel component of $.01677 per KWH (up from $.01611) and directed the establishment of an interim deferred account for variations between actual fuel expense incurred and the base fuel component revenues, providing consideration of the deferred amounts in the next general rate case hearing now planned for the third quarter of 1984. At December 31, 1983 the Company has deferred $1,627,000 of costs incurred in excess of such base fuel component revenues.

(h) Income Taxes. Comprehensive interperiod income tax allocation has been observed, beginning in 1976, for all significant timing differences. In compliance with regulatory accounting, income taxes are allocated between operating income and other income, principally with respect to interest charges related to construction work in progress. The Company and its domestic subsidiaries file consolidated federal income tax returns. Income taxes are allocated among the companies based upon the ratios of their respective "separate tax liabilities" to the consolidated tax liability. See Note 5 with respect to certain other income tax information.

(i) Investment Tax Credits. Investment tax credits are being amortized over the service lives of the property

(j) Preferred and Preference Dividends. Preferred and preference dividends declared and charged to retained earnings include amounts applicable to the first quarter of the following year, except for the Preferred Stock A series which dividends are wholly applicable to the year in which declared.

(k) Retirement Plan. The Company has a noncontributory retirement plan for all full-time employees and is funding the costs accrued under the plan. Retirement plan costs for 1983, 1982 and 1981 were approximately $14,256,000, $15,946,000 and $11,223,000, respectively. The actuarial present value of accrued benefits (assuming rates of return of 11 percent and 14 percent, respectively) and the market value of assets available for benefits, as of the most recent valuation dates, are as follows (in thousands):

	January 1,	
	1983	1982
Actuarial present value of accrued plan benefits:		
Vested	**$ 52,094**	$35,643
Nonvested	**7,309**	4,391
Total	**$ 59,403**	$40,034
Market value of assets available for benefits	**$103,640**	$69,995

(l) Other Policies. Other property and investments are stated principally at cost, less accumulated depreciation where applicable. Materials and supplies inventories are stated at average cost. The Company maintains an allowance for doubtful accounts receivable (1983, $2,477,000; 1982, $1,757,000). Bond premium, discount and expense are amortized over the life of the related debt.

2. Investment in Coal-Mining Subsidiaries

On November 29, 1983, the Company acquired the remaining 20 percent interests in its two coal-mining subsidiaries, Leslie Coal Mining Company (Leslie) and McInnes Coal Mining Company (McInnes).

At December 31, 1983, Leslie's and McInnes' total assets were approximately $131 million. The Company has guaranteed their obligations of approximately $108.5 million.

The Company purchased coal from the subsidiaries for $21,843,000, $48,178,000 and $37,314,000 during 1983, 1982 and 1981, respectively, representing the costs of production for the mines. During 1982, the Company wrote off the accumulated excess of costs of production over fair market value of its coal purchases that had been previously deferred. In 1983 the Company charged $49,868,000 to other operation expense for possible losses on its investments in the mines. The subsidiaries suspended production in the first quarter of 1983 and the Company has since then recorded in other income the carrying charges and other expenses of approximately $1,300,000 per month. The Company currently plans to sell the properties. Pickands Mather & Company, the previous minority owner, continues to manage and operate the mines.

3. Capital Stock Issued and Reserved

Capital stock shares have been issued as follows, representing the total changes in the respective accounts in the years indicated (in thousands):

	1983	1982	1981
Common stock:			
Public offerings			3,000
SPSP	**812**	669	590
ADRP	**2,034**	1,722	1,257
ESOP	**494**	73	70
CSOP	**310**	232	14
Total	**3,650**	2,696	4,931
Preferred Stock—redemption required:			
Serial preferred stock $14.00 Series			400

At December 31, 1983, 1,425,211 shares of common stock were reserved for issuance under the Stock Purchase-Savings Program for Employees (SPSP), 6,134,960 shares under the Automatic Dividend Reinvestment Plan (ADRP), 1,080,406 shares under the Employee Stock Ownership Plan (ESOP) and 1,444,432 shares under the Customer Stock Ownership Plan (CSOP).

4. Notes Payable and Lines of Credit

At December 31, 1983, the Company had firm, unused lines of credit with various financial institutions totaling $206,690,000 including necessary amounts to back up the outstanding current liability portion of commercial paper; and, in connection with these lines of credit, is required to maintain average compensating balances in various banks of $952,500 and pay commitment fees of approximately $61,000 per month. Such lines of credit are reviewed periodically, at which time they may be renewed or canceled.

5. Income Taxes

The provisions for income tax expense are composed of the following (in thousands):

	Year Ended December 31,		
	1983	1982	1981
Included in operating expenses:			
Currently payable taxes—Federal	$ 7,316	$ 29,055	$ 52,732
—State	(106)	18,933	(427)
Deferred taxes, net—Federal	142,887	913	80,854
—State	19,137	(1,939)	14,237
Investment tax credit adjustments, net	(6,791)	86,660	(28,400)
Total	162,443	133,622	118,996
Included in other income (a):			
Reduction in currently payable taxes—Federal	(9,791)	(1,088)	(58,026)
—State	(813)	(1,524)	(1,037)
Deferred taxes—Federal (a)	(18,238)	(35,514)	26,720
—State (a)	(2,337)	(2,179)	(3,334)
Investment tax credit adjustments, net	101	1,833	(169)
Total	(31,078)	(38,472)	(35,846)
Total income tax expense	$131,365(a)	$ 95,150(a)	$ 83,150(a)

(a) Deferred income tax provisions totaling $30,871,000 for 1983, $41,948,000 for 1982 and $37,277,000 for 1981 related to the tax effects of the allowance for borrowed funds charged to the cost of plant are reflected in the statements of income as a reduction in the Allowance for Borrowed Funds Used During Construction - Credit.

Provisions for net deferred income taxes related to the following (in thousands):

	1983	1982	1981
Differences between book depreciation and amortization and tax deductions for property costs:			
Pre-operational tax deductions (taxes and other costs capitalized, etc.)-originating differences	$ 11,091(b)	$ 11,863(b)	$ 8,515(b)
Nuclear fuel disposal costs	41,874	(19,466)	526
Accelerated depreciation and other property cost differences:			
Originations	62,374	59,131	43,109(c)
Reversals	(32,990)	(37,753)	
Deferred recognition of gain on sale of generating facilities, net	(4,201)	(94,080)	
Unbilled revenues, net	1,770	(19,729)	
Deferred tax gain on sale of facilities, net	16,660	62,160	
Provision for possible refund of revenues, net	(17)	11,546	5,902
Utilization of subsidiaries' tax losses	8,347	5,871	6,439
Canceled project costs, net	93,432	(14,100)	49,373
Tax loss carryforward	(39,659)		
Miscellaneous other timing differences, net	(17,232)	(4,162)	4,613
Total provisions for deferred income taxes, net	$141,449	$(38,719)	$118,477

(b) Excludes deferred tax provisions relating to tax effects of borrowed funds capitalized (see (a) above).

(c) Reclassification of detail for originations and reversals for 1981 is not practical.

A reconciliation of the Company's effective income tax rate (computed by dividing total income tax expense, including amounts reflected as a reduction in AFUDC on borrowed funds, by pretax income) to the statutory federal income tax rate follows:

	Year Ended December 31,		
	1983	1982	1981
Effective income tax rate	40.4%	37.6%	37.2%
The effects of including AFUDC on other funds in pretax income	12.5	14.0	14.8
Effective income tax rate, excluding AFUDC on other funds from pretax income	52.9	51.6	52.0
State income taxes, net of federal income tax benefit	(3.4)	(3.8)	(3.3)
Other differences, net	(3.5)	(1.8)	(2.7)
Statutory federal income tax rate	46.0%	46.0%	46.0%

At December 31, 1983, the Company had generated but not utilized investment tax credits totaling approximately $109 million (including $10 million of ESOP credits). The Company also generated a tax loss carryforward estimated at $81 million in 1983 and expected to be utilized in 1984.

6. Harris Unit No. 2

In December 1983, the Company canceled further construction on Harris Unit No. 2, a 900,000 kilowatt nuclear generating unit planned for completion in 1990. The Company's share of the estimated final investment in the jointly owned canceled unit is $315 million. The Company is seeking regulatory permission to write off the costs over a period of ten years and to recover such costs through rates.

7. Joint-Ownership of Generating Facilities

The North Carolina Eastern Municipal Power Agency (Power Agency), which members include a majority of the Company's previous municipal wholesale customers, has acquired undivided ownership interests in certain generating facilities of the Company. The Company and Power Agency are entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share, on a current basis, of additional construction costs, fuel inventory purchases and operating expenses for each unit. Power Agency's payment obligation with respect to cancellation costs for Harris Units Nos. 2, 3 and 4 is 12.94 percent of such costs.

At December 31, 1983, the Company's ownership interests and investments in the jointly owned generating facilities were as follows (dollars in millions):

			Company Investment*	
Plant or Unit (Type Fuel)	Megawatt Capability	Ownership Interest	Plant in Service	Under Construction
Mayo Plant (Coal)	1,440**	83.83%	$420.5	$ 13.2
Harris Plant (Nuclear)	900**	83.83%		1,438.7
Brunswick Plant (Nuclear)	1,580	81.67%	729.6	100.9
Roxboro Unit No. 4 (Coal)	700	87.06%	186.7	.1

*Does not include nuclear fuel costs.
**Design target capability.

The Company does not maintain its accumulated depreciation accounts on a separate unit basis and, therefore, amounts applicable to the Mayo Plant, Brunswick Plant and Roxboro Unit No. 4 are not shown above. The Company's share of expenses for the jointly owned units is included in the appropriate expense category in the statements of income.

The total gain from the sale of the generating facilities to the Power Agency was $32.3 million net of income taxes and is being amortized to other income over three years beginning October 1, 1983.

In connection with the sale of these facilities, the Company is obligated to purchase portions (generally starting at 50 percent) of the Power Agency's ownership capacity and energy for the Mayo and Harris units, commencing with commercial operation of each unit and declining ratably during the following fifteen-year period. The minimum payments applicable to Mayo Unit No. 1 and Harris Unit No. 1 are presently estimated at $5,561,000, $5,168,000, $35,285,000, $38,588,000, and $35,786,000, for the years 1984 through 1988, respectively, and $210,195,000 for the period 1989 through 2000, representing total estimated future minimum payments of $330,583,000 for such capacity. Variable costs of such purchases are primarily fuel costs, maintenance and other operation expenses for the respective units. Contractual purchases from Mayo Unit No. 1 commenced on its commercial operation date, March 1, 1983, and totaled $14,800,000 for 1983.

8. Commitments and Contingencies

(a) Construction and Nuclear Fuel. The Company has incurred substantial commitments in connection with its construction program. Construction expenditures are estimated to be $1.7 billion and nuclear fuel expenditures $278 million for 1984 through 1986 in connection with that program.

(b) Leases. Rental commitments for operating leases and for unrecorded capital leases at December 31, 1983 are not material with respect to the Company's financial position or results of operations.

(c) Insurance. The Company is a member of Nuclear Mutual Limited (NML), established to provide insurance coverage against property damage to insured's nuclear generating facilities. The Company is insured thereunder for $500 million at the Brunswick Plant and $500 million at the Robinson Plant. The Company currently would be subject to maximum retrospective premium assessments of approximately $65 million in the event losses at insured facilities exceed premiums, reserves, reinsurance and other NML resources, which are at present more than $300 million.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL), initially established to provide insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages of members' nuclear generating units. The Company is insured thereunder for $2,500,000 per week for 12 months (starting 26 weeks after the outage) and for $1,250,000 per week for the next 12 months for each operating nuclear generating unit. NEIL also provides decontamination and excess property insurance for nuclear generating facilities. The Company is insured thereunder for $435 million excess of $500 million at both its Brunswick and Robinson plants. The Company currently would be subject to retrospective premium assessments of up to approximately $23 million with respect to the incremental replacement power costs coverage and $15 million with respect to the decontamination and excess property coverage in the event covered expenses at insured facilities exceed premium reserves, reinsurance and other NEIL resources.

The Company's public liability for a nuclear incident is protected up to the maximum limit on public liability claims pursuant to the Price-Anderson Act, which is $580 million for each occurrence, through conventional insurance pools and through an industry retrospective assessment program. In the event that public liability claims from an insured nuclear incident exceed the primary financial protection provided by the insurance pools, which is currently $160 million, the Company would be subject to a pro rata assessment of up to a maximum of $15 million with respect to any single nuclear incident and an aggregate maximum of $30 million within any calendar year.

(d) Claims. There are certain claims pending against the Company. In the opinion of the Company, liabilities, if any, arising from these claims would not have a material effect on the financial position or results of operations of the Company.

(e) Nuclear Fuel Disposal Cost. The Nuclear Waste Policy Act of 1982 establishes that the federal government is responsible for the disposal of spent nuclear fuel and that the owners and operators of nuclear generating facilities will make payments to cover those costs. At December 31, 1983, the net remaining accumulated provisions for the estimated costs of such disposal costs incurred through April 6, 1983 are $29,267,000 less than the required payments of $88 million. Amounts attributable to wholesale customers totaling approximately $10 million, previously required to be refunded, may be recovered in proceedings before the FERC. The Company expects to prospectively increase its charges to operations for fuel expense over a reasonable period of time for this change in the estimated costs for spent fuel disposal. The Company must select by June 30, 1985 from one of several payment options for the costs incurred through April 6, 1983. Costs incurred thereafter are paid quarterly.

(f) Harris Units Nos. 3 and 4. In December 1981, the Company eliminated these units from its construction program. Pursuant to regulatory authorizations, the Company began amortizing in July 1982 the costs associated with these units and is recovering the costs through revenues. Amounts amortized to operating expenses totaled $13,251,000 in 1983 and $6,955,000 in 1982.

9. Other Rate Matters

Operating revenues increased $70,616,000 in 1983 over 1982 and $140,548,000 in 1982 over 1981, attributable to general rate increases placed into effect since 1980. Also included in revenues, representing fuel cost billings above a base cost of fuel (as defined for each ratemaking jurisdiction), is $40,617,000 for 1983, $61,645,000 for 1982 and $27,327,000 for 1981.

Auditors' Opinion

To the Board of Directors and Shareholders of Carolina Power & Light Company:

We have examined the balance sheets and schedules of capitalization of Carolina Power & Light Company as of December 31, 1983 and 1982 and the related statements of income, retained earnings and source and use of financial resources for each of the three years in the period ended December 31, 1983. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 6, the Company has canceled plans for construction of a nuclear generating unit and intends to request permission in each of its regulatory jurisdictions to recover its costs related to such unit. The final outcome of this matter cannot presently be determined. In our previous report dated February 11, 1983, our opinion on the above-mentioned 1982 and 1981 financial statements was unqualified; however, in view of the uncertainty referred to above, our present opinion on such financial statements, as expressed herein, is different from that expressed in our previous report.

In our opinion, subject to the effects on the financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty referred to in the preceding paragraph been known, the financial statements referred to above present fairly the financial position of the Company at December 31, 1983 and 1982 and the results of its operations and the source and use of its financial resources for each of the three years in the period ended December 31, 1983, in conformity with generally accepted accounting principles applied on a consistent basis.

Deloitte Haskins & Sells

Raleigh, North Carolina
February 15, 1984

Supplemental Inflation Adjusted Data (Unaudited)

The data, as reported in the primary financial statements, are based on actual, nominal, historical costs. However, during periods of significant changes in general price levels, that nominal dollar information becomes distorted and fails to reflect real economic costs or value. The conventional basis does not account for the event of inflation, i.e., variations over time in the purchasing power or value of the dollar. In an effort to provide financial information about the effects of changing price levels, the Financial Accounting Standards Board issued Statement No. 33, Financial Reporting and Changing Prices, in September 1979. This statement requires most larger companies to disclose (among other things) certain significant historical cost data in constant dollars represented by the average level during the year of the Consumer Price Index for all Urban Consumers (CPI-U) and current cost information concerning the measurement of assets and the expiration of asset values.

The **constant dollar** information on the following pages reflects the nominal historical costs and prices restated by applying the CPI-U in conformity with Statement No. 33.

The **current cost** information on the following pages reflects changes in specific prices of plant from the date the plant was acquired to the present and differs from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general. The current cost of property, plant and equipment, which includes land, land rights, intangible plant, property held for future use and construction-work-in progress, represents the estimated cost of replacing existing plant assets and was determined primarily by indexing the surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. The current cost of nuclear fuel was determined by recent invoice prices. The current year's provision for depreciation and amortization was determined by applying the Company's depreciation and amortization rates to the indexed current cost amounts.

Under ratemaking practices established by regulatory commissions, the Company can recover through revenues only the original cost (historical cost/nominal dollars) depreciation. Therefore, the increase in the dollar amount for the cost of plant (stated in either historical cost/constant dollars or current cost) over the original cost is deemed not presently recoverable and, therefore, must be reflected as a "reduction in assets to net recoverable cost."

To further reflect the economics of regulation, the reduction in asset "cost" is offset to the extent that the plant is financed from sources that have a fixed, or contractural, rate of return and claim against assets of the Company. Under present ratemaking practices, the Company can recover through revenues the contractual rate of return for such capital and, therefore, is able to effectively recover the inflation impact (purchasing power gain or loss) on such capital to the extent reflected in the annual cost rate. Any holding gain associated with such capital (monetary liabilities) is therefore, not realizable and is an offset against the "reduction in assets to net recoverable cost." The treatment given herein to the holding gains on monetary liabilities recognizes that prices charged by the Company are designed to recover for such capital no more than any inflation costs factored into the contractual annual cost rate. Thus, the purchasing power adjustment to the tangible assets, which is not realizable and is written off, as well as the increased operating expenses, results in no financial loss to the owners of the Company (the common shareholders) to the extent of the leverage financing.

This information should be viewed as an estimate of the approximate effects of inflation, rather than a precise measure.

The statement of income, adjusted for changing prices reflects adjustments only with respect to electric utility plant—the area of the Company most affected by inflation. All other items are considered to have been effectively transacted at average 1983 price levels, and therefore, do not require adjustment.

Statement of Income from Continuing Operations Adjusted for Changing Prices for the Year Ended December 31, 1983

	As Reported in the Primary Statements	Constant Dollar Average 1983 Dollars	Current Cost Average 1983 Dollars
		(In Thousands)	
Operating revenues	**$1,647,183**	**$1,647,183**	**$1,647,183**
Operating expenses:			
Operation and maintenance:			
Fuel for generation	517,625	524,411	534,488
Other	440,522	440,522	440,522
Depreciation and amortization	148,342	251,059	257,747
Taxes other than on income	114,295	114,295	114,295
Income tax expense	162,443	162,443	162,443
Total operating expenses	1,383,227	1,492,730	1,509,495
Operating income	263,956	154,453	137,688
Other income—net	132,482	132,482	132,482
Income before interest charges	396,438	286,935	270,170
Net interest charges	157,169	157,169	157,169
Income from continuing operations (excluding reduction to net recoverable cost)	$ 239,269	$ 129,766*	$ 113,001
Other adjustments to reflect the effects of changing prices:			
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 63,908
Increase (reduction) in assets to net recoverable cost		$ (48,233)	154,692
Effect of increase in general price level			(250,068)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			$ (31,468)
Adjustment for purchasing power loss by net monetary liabilities		$ 112,342	$ 112,342

*Including the reduction in assets to net recoverable cost, income from continuing operations would have been $81,533.

**At December 31, 1983 current cost of property, plant and equipment, net of accumulated depreciation was $6,798,429, while historical cost or net cost recoverable through depreciation was $4,571,206.

Five Year Comparison of Selected Financial Data
Adjusted for Effects of Changing Prices

	Year Ended December 31,				
	1983	1982	1981	1980	1979
	(In Millions of Average 1983 Dollars, Except for Per Share Amounts)				
Operating revenues	$1,647.2	$1,587.7	$1,471.9	$1,300.5	$1,270.8
Historical cost information adjusted for general inflation:					
Income from continuing operations (excluding reduction in assets to net recoverable cost)	$ 129.8	$ 120.5	$ 117.3	$ 92.4	$ 128.3
Income from continuing operations per common share (after preferred stock dividend requirements and excluding reduction in assets to net recoverable cost)	$ 1.40	$ 1.29	$ 1.34	$ 1.08	$ 2.20
Net assets at year-end at net recoverable cost	$1,559.7	$1,492.2	$1,446.7	$1,424.3	$1,356.6
Current cost information:					
Income from continuing operations (excluding reduction in assets to net recoverable cost)	$ 113.0	$ 102.2	$ 104.7	$ 79.7	$ 113.0
Income from continuing operations per common share (after preferred stock dividend requirements and excluding reduction in assets to net recoverable cost)	$ 1.13	$ 0.98	$ 1.10	$ 0.82	$ 1.82
Net assets at year-end at net recoverable cost	$1,559.7	$1,492.2	$1,446.7	$1,424.3	$1,356.6
General information:					
Adjustment for purchasing power loss by net monetary liabilities	$ 112.3	$ 116.9	$ 266.9	$ 358.4	$ 373.9
Cash dividends declared per common share	$ 2.46	$ 2.48	$ 2.54	2.66	$ 2.82
Market price per common share at year-end	$ 21.63	$ 21.94	$ 21.47	$ 20.94	$ 24.82
CPI-U—average	298.4	289.1	272.4	246.8	217.4
—year-end	303.5	292.4	281.5	258.4	229.9

Statistical Review Carolina Power & Light Company

(Dollars in Thousands except per share amounts)	1983	1982	1981	1980	1979	1978	1973
Balance Sheet Data (End of Period)							
Total Utility Plant other than Nuclear Plant	**$5,340,078**	$5,024,397	4,854,337	4,490,984	3,882,776	3,286,303	1,872,859
Construction Work in Progress	**$1,697,551**	1,994,906	1,854,177	1,616,513	1,327,311	896,126	588,760
Total Nuclear Fuel	**$ 264,802**	231,518	254,477	218,466	220,199	155,418	78,121
Net Utility Plant other than Nuclear Fuel	**$4,455,828**	4,232,384	4,136,537	3,863,576	3,320,598	2,802,044	1,645,214
Total Assets	**$5,293,606**	4,950,955	4,715,835	4,241,607	3,647,913	3,135,847	1,780,369
Capitalization							
Common stock and retained earnings	**$1,586,441**	1,462,165	1,364,692	1,233,368	1,045,150	985,774	531,297
Preference stock	**47,900**	47,900	47,900	47,900	47,900	47,900	
Preferred stock—Redemption not required	**238,118**	238,118	238,118	238,118	238,118	238,118	173,801
—Redemption required, net	**214,785**	214,743	214,700	175,100	100,000	50,000	50,000
First mortgage bonds, net[1]	**1,719,744**	1,674,449	1,574,425	1,564,400	1,411,613	1,222,527	832,548
Other long-term obligations[1]	**211,928**	281,375	355,023	149,067	96,077	133	50,253
Total	**$4,018,916**	3,918,750	3,794,858	3,407,953	2,938,858	2,544,452	1,637,899
Noncurrent Deferred Income Taxes	**$ 531,201**	389,731	421,289	307,626	263,074	220,174	38,594
Deferred Investment Tax Credits	**174,112**	180,700	92,207	120,776	129,040	105,141	10,755
Total	**$ 705,313**	570,431	513,496	428,402	392,114	325,315	49,349
Ratio of Accumulated Depreciation to Utility Plant in Service	**% 24.4**	26.3	24.0	21.9	22.1	20.3	17.7
Percent of Total Capitalization							
Common stock and retained earnings	**39.5**	37.3	36.0	36.2	35.6	38.7	32.4
Preference stock	**1.2**	1.2	1.3	1.4	1.6	1.9	
Preferred stock—Redemption not required	**5.9**	6.1	6.3	7.0	8.1	9.4	10.6
—Redemption required	**5.3**	5.5	5.6	5.1	3.4	1.9	3.1
First mortgage bonds, net[1]	**42.8**	42.7	41.5	45.9	48.0	48.1	50.8
Other long-term obligations[1]	**5.3**	7.2	9.3	4.4	3.3	—	3.1
Total	**100.0**	100.0	100.0	100.0	100.0	100.0	100.0
Ratio of Bonds to Net Utility Plant Other than Nuclear Fuel	**38.6**	39.6	38.1	40.5	42.5	43.6	50.6
Summary Results of Operations							
Operating Revenues	**$1,647,183**	1,538,165	1,343,558	1,075,604	925,910	903,438	341,206
Operating Expenses							
Operation and maintenance	**958,147**	925,763	779,462	658,815	501,619	459,663	185,697
Depreciation and amortization	**148,342**	126,355	110,409	88,701	88,396	80,356	31,845
Taxes—other than on income	**114,295**	104,300	97,288	80,209	70,796	68,314	28,706
Income tax expense	**162,443**	133,622	118,996	75,693	94,642	124,888	21,268
Total operating expenses	**1,383,227**	1,290,040	1,106,155	903,418	755,453	733,221	267,516
Operating Income	**263,956**	248,125	237,403	172,186	170,457	170,217	73,690
AFUDC, Net of Deferred Income Taxes	**126,757**	141,618	130,937	113,398	80,785	53,173	38,093
Other Income—Income Tax Credit	**31,078**	38,472	35,846	35,417	22,113	13,237	10,477
Other Income (Deductions)—Net	**6,477**	13,919	8,593	4,366	1,858	4,203	393
Total Interest Charges	**(188,999)**	(214,987)	(209,182)	(163,979)	(121,969)	(98,087)	(56,654)
Net Income	**239,269**	227,147	203,597	161,388	153,244	142,743	65,999
Preferred and preference stock dividend requirements	**44,605**	44,605	42,660	34,641	28,263	26,926	13,017
Earnings for Common Stock	**194,664**	182,542	160,937	126,747	124,981	115,817	52,982
Dividends declared on common stock	**1[illegible]0,423**	138,878	123,578	104,865	84,066	71,511	32,691
Earnings Invested in the Business	**$ 4[illegible]**	43,664	37,359	21,882	40,915	44,306	20,191
Earnings Per Share—Weighted Average	**$ 3.2[illegible]**	3.17	3.06	2.73	3.06	3.10	2.58
Return on Average Common Stock Equity	**% 12.77**	12.91	12.61	11.09	12.30	12.93	11.35
Times Earned—Fixed charges[2]	**2.89**	2.55	2.42	2.31	2.79	3.39	2.34
—Fixed charges and preferred and preference dividend requirements[3]	**2.14**	1.95	1.87	1.80	2.10	2.34	1.85
Common Stock Data							
Shares Outstanding (000's)—Year-end	**62,485**	58,835	56,139	51,208	41,386	40,454	23,234
—Average	**60,645**	57,539	52,554	46,471	40,841	37,355	20,554
Book Value per Share at Year-end	**25.35**	24.81	24.26	24.02	25.19	24.30	22.87
Dividends Declared per Share	**2.46**	2.40	2.32	2.20	2.05	1.90	1.56
Payout percent	**76.6**	75.7	75.8	80.6	67.0	61.3	60.5
Number of Shareholders at Year-end	**104,918**	103,163	101,817	103,662	87,817	84,645	47,804

[1] Includes current maturities of long-term debt.

[2] For purposes of this ratio, earnings represent net income plus income taxes and fixed charges; fixed charges represent interest charges plus an imputed interest factor portion of rentals.

[3] For purposes of this ratio, earnings represent net income plus income taxes and fixed charges; dividends represent preferred and preference dividend requirements multiplied by the ratio that income before income taxes bears to net income.

	1983	1982	1981	1980	1979	1978	1973
Revenue (Thousands)							
Residential	**$518,246**	473,546	415,650	342,239	293,575	292,309	117,559
Commercial	**325,468**	302,453	250,107	195,436	171,715	166,867	65,647
Industrial	**478,549**	433,942	386,050	296,742	267,310	249,925	84,366
Government and Municipal	**40,972**	39,152	36,341	30,403	29,484	31,020	11,632
Sales for Resale	**262,890**	275,489	244,656	202,360	155,828	155,925	57,435
Miscellaneous Revenues	**21,058**	13,583	10,754	8,424	7,998	7,392	4,567
Total Operating Revenues	**$1,647,183**	1,538,165	1,343,558	1,075,604	925,910	903,438	341,206
Load Data							
Electric Energy Sales (Millions)							
Residential ... Kwh	**8,010**	7,647	7,746	7,870	7,195	7,208	5,937
Commercial	**5,546**	5,341	5,072	4,935	4,590	4,503	3,628
Industrial	**10,210**	9,520	9,968	9,791	9,609	9,013	7,885
Government and Municipal	**768**	753	823	864	917	963	922
Sales for Resale							
Standard Rate Schedule							
Power Agency Participants		1,129	2,593	2,561	2,363	2,334	1,869
Other	**4,455**	4,253	4,285	4,261	3,994	3,972	2,988
Power Agency contract requirements	**1,896**	1,840					
Other Special Contract							853
Total Electric Energy Sales	**30,885**	30,483	30,487	30,282	28,668	27,993	24,082
Company Uses, Losses and Unaccounted For	**1,897**	1,349	1,863	1,901	1,632	1,709	1,501
Total Energy Requirements ... Kwh	**32,782**	31,832	32,350	32,183	30,300	29,702	25,583
Electric Energy Supply (Millions)							
Generated—Steam—Fossil ... Kwh	**23,799**	23,079	22,372	22,299	18,336	14,591	19,875
Generated—Steam—Nuclear	**7,775**	6,876	9,344	8,955	10,802	13,891	3,764
Generated—Hydro	**816**	735	437	680	1,019	716	891
Generated—Other Fuel	**35**	23	117	224	146	294	113
Purchased and interchanged—Net	**357**	1,119	80	25	(3)	210	940
Total Energy Supply (Company Share) ... Kwh	**32,782**	31,832	32,350	32,183	30,300	29,702	25,583
Ownership Share to Power Agency	**1,529**[8]	361					
Total Combined System Energy Supply ... Kwh	**34,311**	32,193					
Peak Demand of Firm Load (000's)							
Total Combined System ... KW	**6,926**	6,602	6,402	6,139	5,907	5,605	4,923
Less Power Agency Portion	**304**[8]	-0-[4]					
Company Total Peak Demand	**6,622**	6,602	6,402	6,139	5,907	5,605	4,923
Less Sales to Power Agency and Participants	**449**	637					
Company Net Peak Demand ... KW	**6,173**	5,965	6,402	6,139	5,907	5,605	4,923
Total Capability at Year End[5] (000's)							
Fossil Fuel Plants ... KW	**6,291**	5,561	5,519	5,519	4,869	4,869	4,352
Nuclear Plants	**2,245**	2,245	2,245	2,245	2,245	2,245	715
Hydro Plants	**214**	214	214	214	214	214	214
Purchased	**75**	75	75	75	128	128	280
Total Combined System Capability	**8,825**	8,095					
Less Power Agency Owned Portion	**494**	262					
Add Capability Purchased From Power Agency	**75**						
Total Company Capability ... KW	**8,406**	7,833	8,053	8,053	7,456	7,456	5,561
Miscellaneous							
Customers at Year End							
Residential	**680,581**	660,850	647,491	632,209	617,393	601,947	535,607
Other	**115,339**	111,177	110,033	109,424	107,624	106,212	96,844
Total	**795,920**	772,027	757,524	741,633	725,017	708,159	632,451
Average Revenue Per KWH							
Residential ... Cents	**6.47**	6.19	5.37	4.35	4.08	4.06	1.98
Commercial	**5.87**	5.66	4.93	3.96	3.74	3.71	1.81
Industrial	**4.69**	4.56	3.87	3.03	2.78	2.77	1.07
Total Energy Sales	**5.27**	5.00	4.37	3.52	3.20	3.20	1.39
Residential							
Average Annual Energy Use ... Kwh	**11,889**	11,663	12,087	12,558	11,785	12,113	11,276
Average Annual Bill	**$ 769.27**	722.26	648.57	546.11	480.84	491.22	223.29
Average Annual Heat Rate—All Plants ... (BTU Per Net KWH)	**10,494**	10,472	10,684	10,456	10,322	10,542	10,016
Average Cost Per Million BTU[6]							
All Fuels ... Cents	**156.1**	155.4	135.1	124.9	100.8	90.4	44.6
Nuclear Fuel	**42.1**	35.8	37.2	35.7	35.4	40.3	18.0
Annual Load Factor ... percent	**56.6**[7]	55.7[7]	57.7	59.7	58.6	60.5	59.9

[4]The 1982 peak occurred before Power Agency closing on April 21, 1982.
[5]Represents peak capability, based on summer peak conditions and assuming all units are available for operation.
[6]Does not reflect non-Company-owned portion of output from jointly owned generating units.
[7]Reflects demand and energy for Power Agency's portion of the joint facilities.
[8]Net of purchases by the Company from Power Agency.

Board of Directors
at January 1, 1984

Daniel D. Cameron, Sr.
President, Atlantic Telecasting Corporation
(a telecasting station)
Wilmington, N.C. (1970)

Felton J. Capel
President, Century Associates of North Carolina
(distributors of stainless steel cookware, china and crystal)
Southern Pines, N.C. (1972)

George H. V. Cecil
President, Biltmore Dairy Farms, Inc.
(dairy producers, processors and distributors)
Asheville, N.C. (1976)

Charles W. Coker, Jr.
President, Sonoco Products Company
(manufacturer of paper, paper products and plastics)
Hartsville, S.C. (1975)

William E. Graham, Jr.
Executive Vice President of the Company
Raleigh, N.C. (1980)

Margaret T. Harper
Owner, Stevens Agency
(an insurance agency)
Southport, N.C. (1975)

L. H. Harvin, Jr.
Chairman of the Executive Committee of Rose's Stores, Inc.
(retail stores)
Henderson, N.C. (1958)

Karl G. Hudson, Jr.
Executive Vice President and General Manager,
Hudson-Belk Company
(retail department store)
Raleigh, N.C. (1967)

Edward G. Lilly, Jr.
Executive Vice President and Chief Financial Officer
of the Company
Raleigh, N.C. (1971)

John G. Medlin, Jr.
President and Chief Executive Officer of the Wachovia
Corporation and Wachovia Bank & Trust Company, N.A.
Winston-Salem, N.C. (1982)

A.C. Monk, Jr.
Chairman of the Board, President and Chief Executive Officer,
A.C. Monk and Company, Inc.
(leaf tobacco processors and exporters)
Farmville, N.C. (1976)

Sherwood H. Smith, Jr.
Chairman/President and Chief Executive Officer of the Company
Raleigh, N.C. (1971)

Horace L. Tilghman, Jr.
Real Estate and Investments
Marion, S.C. (1961)

Edwin E. Utley
Executive Vice President and Chief Operating Officer
of the Company
Raleigh, N.C. (1982)

Committees of the Board

Executive Committee
Sherwood H. Smith, Jr., Chairman
William E. Graham, Jr.
Edward G. Lilly, Jr.
Edwin E. Utley

Personnel, Executive Development and Compensation Committee
Charles W. Coker, Jr., Chairman
Felton J. Capel
Margaret T. Harper
L. H. Harvin, Jr.
John G. Medlin, Jr.

Customer and Public Relations Committee
Daniel D. Cameron, Sr., Chairman
Felton J. Capel
George H. V. Cecil
Margaret T. Harper
Karl G. Hudson, Jr.

Forecasting, System Development and Finance Committee
Karl G. Hudson, Jr., Chairman
George H. V. Cecil
John G. Medlin, Jr.
A. C. Monk, Jr.
H. L. Tilghman, Jr.

Financial Audit and Corporate Performance Committee
L. H. Harvin, Jr., Chairman
Daniel D. Cameron, Sr.
Felton J. Capel
Charles W. Coker, Jr.
A. C. Monk, Jr.

Nominating Committee
H. L. Tilghman, Jr., Chairman
Daniel D. Cameron, Sr.
Charles W. Coker, Jr.
L. H. Harvin, Jr.
Karl G. Hudson, Jr.

Officers
at January 1, 1984

Sherwood H. Smith, Jr.
Chairman/President and Chief Executive Officer

William E. Graham, Jr.
Executive Vice President

Edward G. Lilly, Jr.
Executive Vice President and Chief Financial Officer

Edwin E. Utley
Executive Vice President and Chief Operating Officer

Charles D. Barham, Jr.
Senior Vice President and General Counsel
(Group Executive)

James M. Davis, Jr.
Senior Vice President
(Group Executive)

Lynn W. Eury
Senior Vice President
(Group Executive)

Russell H. Lee
Senior Vice President
(Group Executive)

M.A. McDuffie
Senior Vice President
(Group Executive)

Wilson W. Morgan
Senior Vice President
(Group Executive)

Samuel Behrends, Jr.
Vice President

Paul S. Bradshaw
Vice President & Controller

Alan B. Cutter
Vice President

R. Thomas Dwyer, III
Vice President

Norris L. Edge
Vice President

Thomas S. Elleman
Vice President

B. J. Furr
Vice President

Cecil L. Goodnight
Vice President

P. W. Howe
Vice President

Richard E. Jones
Vice President

W. B. Kincaid
Vice President

Mendall H. Long
Vice President

Jack B. McGirt
Vice President

Bobby L. Montague
Vice President

Albert L. Morris, Jr.
Vice President

E. S. Noell
Vice President

Sheldon D. Smith
Vice President

Earl F. Stephenson
Vice President

R. A. Watson
Vice President

L. Thompson Quarles
Treasurer

J. L. Lancaster, Jr.
Secretary

Robert M. Williams
Assistant Secretary

Clifton D. Mann
Assistant Controller

E. Wilson Craig
Vice President-
Northern Division

E. Charles Dyson
Vice President-
Western Division

W. Burt Grant
Vice President-
Central Division

C. Joe Turner
Vice President-
Southern Division

CP&L

Carolina Power & Light Company
P.O. Box 1551, Raleigh, N.C. 27602

ADDRESS CORRECTION REQUESTED

The Company's 30,000 square-mile service area stretches from the mountains to the sea.

1908 75 1983

APPENDIX B

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C.

20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended 12/31/83 — Commission file number 1-3382

CAROLINA POWER & LIGHT COMPANY
(Exact name of registrant as specified in its charter)

North Carolina
(State or other jurisdiction of incorporation or organization)

56-0165465
(I.R.S. Employer Identification No.)

411 Fayetteville Street
Raleigh, North Carolina
(Address of principal executive offices)

27602
(Zip Code)

919-836-6111
(Registrant's telephone number)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock (Without Par Value)	New York Stock Exchange Pacific Stock Exchange
First Mortgage Bonds, 7-3/4% Series due 2002	New York Stock Exchange
$2.675 Preference Stock, Series A (Without Par Value, Cumulative)	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT

Preferred Stock (Without Par Value, Cumulative)
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X. No __.

The aggregate market value of the voting stock held by non-affiliates at January 31, 1984, was $1,778,908,953.

Common Stock (Without Par Value) shares outstanding at February 29, 1984: 63,296,030.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the 1984 proxy statement are incorporated into Part III, Items 10, 11, 12 and 13 hereof.

PART I

ITEM 1. BUSINESS

General

1) Carolina Power & Light Company (Company) is a public service corporation formed under the laws of North Carolina in 1926, and is engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. The Company had 9,003 employees at December 31, 1983. The principal executive offices of the Company are located at 411 Fayetteville Street, Raleigh, North Carolina 27602, telephone, 919-836-6111.

2) The territory served, an area of approximately 30,000 square miles, includes a substantial portion of the coastal plain in North Carolina extending to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section in North Carolina and in South Carolina, and an area in western North Carolina in and around the City of Asheville. The estimated total population of the territory served is approximately 3 million.

3) Electric service is rendered at retail in 219 communities, each having an estimated population of 500 or more, and wholesale service is currently supplied to one joint municipal power agency, 4 municipalities, 18 electric membership corporations and one private electric system.

4) In 1981, the Company entered into certain agreements with North Carolina Eastern Municipal Power Agency (Power Agency), which is composed of former North Carolina municipal wholesale customers of the Company and Virginia Electric and Power Company. Pursuant to such agreements, Power Agency has acquired in a series of closings undivided ownership interests of 18.33% in Brunswick Units Nos. 1 and 2, 12.94% in Roxboro Unit No. 4 and 16.17% in Harris Unit No. 1 and Mayo Units Nos. 1 and 2 (collectively referred to as "Joint Facilities"). The Company constructs and operates the Joint Facilities for Power Agency and provides transmission services, back-stand services and supplemental power as necessary to enable Power Agency to provide its participants with their total electric power requirements. Power Agency's payment obligation with respect to cancellation costs for Harris Units Nos. 2, 3 and 4 is 12.94% of such costs.

5) At December 31, 1983, the Company was furnishing electric service to approximately 796,000 customers. During 1983, 31.5% of operating revenues was derived from residential sales, 29.0% from industrial sales, 19.7% from commercial sales, 16.0% from wholesale sales and 3.8% from other sources. Of such operating revenues, approximately 83.6% was derived from North Carolina and approximately 16.4% from South Carolina.

6) For the twelve months ended December 31, 1983, average revenues per KWH sold to residential, commercial and industrial customers were 6.47 cents, 5.87 cents, and 4.69 cents, respectively. Sales to residential customers were as follows:

Year	Average Annual KWH Use	Average Annual Bill	Revenue per KWH
1979....................	11,785	$480.84	4.08¢
1980....................	12,558	546.11	4.35
1981....................	12,087	648.57	5.37
1982....................	11,663	722.26	6.19
1983....................	11,889	769.27	6.47

7) The highest 60-minute net peak demand to date of 6,926 MW was reached on August 22,1983, during an unusually hot summer period. The Company's generating reserves based on installed capacity and scheduled firm purchases had been forecasted to be approximately 27% at the time of the peak demand. However, due to the unavailability of some generating capacity, actual reserves at the time of the peak were approximately 6%.

8) Total system peak demand for 1981, 1982 and 1983 increased by 4.3%, 3.1% and 4.9%, respectively, as compared with the preceding year. Total system load factors, expressed as the ratio of the average load supplied to the peak load demand, for the years 1981-1983 were 57.7%, 55.7%, and 56.6%, respectively. The Company presently forecasts summer reserves of 27.3% and 23.3% over anticipated system peak load for 1984 and 1985, respectively, based upon the rated Maximum Dependable Capacity of generating units in commercial operation (see "Generating Capability"). It is anticipated, however, that some of the generating units included in arriving at these reserve figures will be unavailable as a result of scheduled outages or environmental and operating problems. See "Environmental Matters" and "Nuclear Matters". The above data include capability and load from Power Agency's portion of the Joint Facilities.

9) The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) with respect to licensing and operation of hydroelectric projects, rates for transmission and sale of electric energy at wholesale, the interconnection of facilities (other than emergency interconnection) and, to the extent the FERC determines, accounting policies and practices. In addition, the Company is subject to regulation by the Nuclear Regulatory Commission (NRC) with respect to the construction and operation of nuclear reactors. With respect to retail service territory, retail rates, issuance of securities and other matters, the Company is subject to regulation in North Carolina by the North Carolina Utilities Commission (NCUC) and in South Carolina by the South Carolina Public Service Commission (SCPSC). The Company is also subject to regulation by federal, state and local authorities with respect to air quality, water quality, and disposal of liquid and solid wastes. See "Retail Rate Matters", "Wholesale Rate Matters", "Environmental Matters", "Nuclear Matters" and "Nuclear Fuel Supply".

Construction Program

1) During 1983 the Company expended approximately $658 million for capital requirements. In addition, the Company expended approximately $67 million in 1983 for the early retirement of First Mortgage Bonds, 11% Series, due April 15, 1984. The Company's estimates of capital requirements for the three years 1984 through 1986, are set forth below. These estimates are subject to continuing review and adjustment.

	Estimated Capital Requirements (In Millions)			
	1984	1985	1986	Total
Construction expenditures	$716	$571	$379	$1,666
Nuclear fuel expenditures	100	68	109	277
Less AFUDC (a)	(112)	(128)	(52)	(292)
Net expenditures (b)	704	511	436	1,651
Harris Units 2, 3, and 4 cancellation costs (c)	46	14	14	74
Long-term debt and preferred stock retirement (d)	2	4	5	11
Total	$752	$529	$455	$1,736

(a) As prescribed in regulatory systems of accounts, an allowance for borrowed and other funds used to finance electric utility plant construction less applicable income taxes (AFUDC) is charged to the cost of plant (see Note 1(d) to Financial Statements in ITEM 8).

(b) Reflects reductions of approximately $80 million, $[illegible]3 million and $41 million for 1984, 1985 and 1986, respectively, in net capital requirements resulting from Power Agency's projected payment of its proportionate share of capital expenditures related to the Mayo Plant, the Harris Plant, the Brunswick Plant and Roxboro Unit No. 4 (see "Financing Program" and "Construction Program" below).

(c) Reflects the Company's share of costs and charges expected to be incurred in connection with the cancellation of Harris Unit Nos. 2, 3 and 4.

(d) Excludes nuclear fuel continuous funding arrangements.

The above table reflects (i) the projected in-service date for Harris Unit No. 1 in March 1986, and (ii) the projected in-service date for Mayo Unit No. 2 in March 1991.

2) At the December 21, 1983 meeting of the Company's Board of Directors, the Board approved the immediate cancellation of Harris Unit No. 2. The Company's share of the net cost for Harris Unit No. 2 is expected to be approximately $315 million, including its investment to date, estimated cancellation costs and the payment to Power Agency discussed below. The Company will seek to amortize its costs over a ten-year period and recover those costs through rates. (See "Retail Rate Matters".) The Board also approved a change in the scheduled in-service date of Mayo Unit No. 2 from 1992 to 1991.

3) As a result of the cancellation of Harris Unit No. 2, the Power Agency's ownership interest in the unit was reduced by 3.23% to 12.94%. In conjunction with the change in ownership interest, an amount was paid to Power Agency; this amount is included in the costs of cancellation set forth above in paragraph 1 of Construction Program. Power Agency's share of any costs of cancellation for Harris Unit No. 2 is 12.94%.

4) Approximately $680 million reflecting the Company's share for construction of Harris Unit No. 1 and Mayo Unit No. 2 is included in the estimated 1984-1986 construction expenditures. The estimated costs of these units reflect the projected in-service dates, estimated increases in the costs of labor, material and equipment, estimated AFUDC and the inclusion of all eligible Construction Work in Progress (CWIP) in the rate base in each jurisdiction for Harris Unit No. 1. The continuation of all eligible CWIP in rate base for Harris Unit No. 1 has been assumed in determining the level of capital requirements although the Company is unable to predict what level of CWIP, if any, will be included in rate base in the future. If CWIP were not included in rate base during the 1984-86 time period, the cost of Harris Unit No. 1 would increase by a total of approximately $216 million.

5) The Company's current construction schedule for new generating units is as follows:

Unit	Design Target Capacity	Type	Projected In-Service Date	Estimated Cost (Millions)(a)
Harris No. 1	900 MW	Nuclear	1986	$2,546
Mayo No. 2	720 MW	Coal	1991	778

(a)Includes costs expended to date, AFUDC and, with respect to Harris Unit No. 1, inclusion of all eligible CWIP in rate base. Does not include (i) costs of land or (ii) reductions as a result of the sale of a 16.17% undivided ownership interest in these facilities to Power Agency.

6) The Company's investment, including AFUDC and land costs, at December 31, 1983 for its 83.83% share of units under construction was (in thousands):

Harris Unit No. 1	$1,438,723
Mayo Unit No. 2	13,156
Total	$1,451,879

7) The current schedule for engineering, procurement, construction, and testing activities is intended to achieve commercial operation of Harris Unit No. 1 in March 1986. Some of these engineering, procurement, construction, and testing activities are currently behind schedule. The Company believes the steps it is taking to accelerate activities in these areas should enable Harris Unit No. 1 to begin commercial operation in March 1986. Should these steps be unsuccessful or should factors involving

governmental, regulatory, design, procurement, construction, testing, and start-up uncertainties inherent in such major projects adversely affect the current schedule, it would be necessary to revise the scheduled commercial operation date and increase the estimated cost of Harris Unit No. 1.

8) Further changes in the above schedule and estimated construction expenditures may result from the Company's continuing review of its construction program, its financial position, its intensified conservation and load management program, general economic conditions, costs, projected load growth, licensing delays and other factors.

9) The NCUC periodically holds hearings in which forecasts of future growth, the need for capacity additions for North Carolina and the reliability and safety of proposed plants are considered. In December 1983, the NCUC issued its Order adopting an updated load forecast and plan for meeting long-range needs for electric generation facilities in North Carolina. The NCUC found that the Company's probable rate of growth in peak demand from 1982 through 1997 is in the range of 1.9% to 3.4% per year. The Company projects a 2.6% annual growth in peak demand for electricity through 1995.

10) On November 3, 1983, the Conservation Council of North Carolina filed a complaint with the NCUC seeking revocation of the Certificate of Public Convenience and Necessity for the Harris Plant on the grounds that the plant is no longer needed. Although, based on the allegations and information in the Complaint, at this time the Company does not expect this proceeding to affect the construction schedule for Harris No. 1, the Company cannot predict the outcome of this matter.

Financing Program

1) The Company presently estimates that to meet capital requirements external funds of approximately $550 million and $200 million in 1984 and 1985, respectively, will be needed from sales of long-term securities and from short-term borrowings. Included in the above are approximately $100 million and $90 million in 1984 and 1985, respectively, expected to be obtained from sales of common stock through its automatic dividend reinvestment plan, employee stock plans and customer stock ownership plan. The Company expects that it will have little or no external funds requirements in 1986. The remainder of the Company's capital requirements through 1986 are expected to come from internally generated funds. The Company may from time to time sell additional securities beyond what is needed to meet capital requirements. The amounts and timing of the sales of securities will depend upon market conditions and the specific needs of the Company.

2) The final Power Agency closing occurred on April 29, 1983 which increased to approximately $639 million the total deposits made by Power Agency into a Trust in 1982 and 1983. The funds set aside in the Trust have been applied by the Trustee to purchase property for the Company. The total of payments for associated fuel inventories; fuel, construction and operating advances; and other costs billed pursuant to the agreements and paid at the closings directly to the Company totaled approximately $34 million. The use of the funds in the Trust and Power Agency's contribution for ongoing construction reduced the Company's financing requirements by $299 million during 1983. Power Agency's contribution for ongoing construction and nuclear fuel is expected to reduce financing requirements by $174 million for the 1984-1986 period.

3) In January 1983, the Company filed a shelf registration statement with the Securities and Exchange Commission for $250 million in First Mortgage Bonds. In December 1983, the Company issued under such shelf registration $100 million of First Mortgage Bonds, 12 7/8% Series, due December 1, 2013. The amounts and timing of further sales of bonds under the shelf registration will depend on market conditions and the specific needs of the Company.

4) In March 1983, the Company participated in the issuance by the Industrial Facilities and Pollution Control Financing Authorities of Wake County and New Hanover County, North Carolina, of $48,485,000 and $5,970,000 principal amount, respectively, of Pollution Control Revenue Bonds, Adjustable Rate Option Bond Series 1983, due April 1, 2009. In connection therewith, the Company issued two series of its First Mortgage Bonds equal in principal amount to the respective issues of pollution control revenue bonds in order to provide funds sufficient to pay principal and interest on such pollution control revenue bonds.

5) In December 1983, the Company participated in the issuance by Darlington County, South Carolina of $34,700,000 principal amount of Annual Tender Pollution Control Revenue Bonds, Series 1983, due November 1, 2010. In connection therewith, the Company issued a series of its First Mortgage Bonds equal in principal amount to and bearing interest at the same rate as the issue of pollution control revenue bonds in order to provide funds sufficient to pay principal and interest on such pollution control revenue bonds.

6) See ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations for further analysis and discussion of the Company's financing plans and capital resources and liquidity.

Retail Rate Matters

1) On February 21, 1984, the Company filed with the NCUC a request for a 12.6% increase in its retail rates (Docket No. E-2, Sub 481). The increase would provide an additional $151.6 million in annual revenues based on the test year ending September 30, 1983. The requested rate of return on common equity is 16.5% based on a common equity ratio to total capitalization of 40.0%. The proposed overall rate of return is 12.52%. The request includes $29.5 million related to an increase to $695 million of CWIP in rate base for Harris Unit No. 1 and $24.2 million to recover, by amortization over a 10-year period, the Company's investment in its cancelled Harris Unit No. 2 which, as of December 31, 1983, was $263.7 million. The Company is unable to predict the outcome of this matter.

2) On September 8, 1982, the Company filed a request (Docket No. 82-328-E) with the SCPSC for a general rate increase of 19.96% which would increase retail rates by approximately $44.8 million annually. On September 28, 1983, the SCPSC issued its order granting a rate increase of $34.9 million, a 14.74% increase over existing rates, effective October 7, 1983. The SCPSC allowed the Company a rate of return on common equity of 14.50% after a penalty of .81% for plant operations. The SCPSC also allowed the inclusion of $52.7 million of CWIP in rate base without an AFUDC offset. In a separate fuel adjustment proceeding, the SCPSC approved the same 1.725 cents per kwh fuel component as was previously in effect.

3) On February 11, 1983, the Company filed with the NCUC a request for a 14.93% increase in its retail rates (Docket No. E-2, Sub 461). The requested increase would have provided an additional $164.9 million in annual revenues based on the test period ending September 30, 1982. On September 19, 1983, the NCUC issued its order granting a rate increase of $90.855 million, an 8.22% increase over existing rates. The NCUC allowed the Company a rate of return on common equity of 14.5% after a penalty of .75% for plant operations. The NCUC also allowed the inclusion of $539.8 million of CWIP in rate base. The NCUC approved a base fuel component of 1.686 cents per kwh, an increase from the existing fuel component of 1.611 cents per kwh but below the requested fuel component of 1.818 cents per kwh. The Public Staff and the Attorney General of the State of North Carolina filed motions for reconsideration of the fuel component. The Company filed a motion for reconsideration of the NCUC's requirement to credit to customers over a three-year period investment tax credits previously taken on property sold to Power Agency. On December 7, 1983 the NCUC issued its Order on the motions for reconsideration. On reconsideration, the NCUC adopted the Company's position with respect to investment tax credits related to property sold to Power Agency that such credits be amortized back to the customer over the remaining life of the assets involved rather than over a three-year period. The NCUC did, however, order the Company to seek a ruling from the IRS so that the NCUC could determine the appropriate treatment in future rate cases. With respect to the fuel component, the NCUC reduced the original finding of 1.686 cents per kwh to 1.677 cents per kwh. The NCUC also required the Company to establish a deferred fuel expense account to accumulate any net overcollections of fuel costs. The NCUC will require the Company to refund to its customers any overcollections in the account in subsequent fuel proceedings and general rate cases. The NCUC did not provide for a true-up in the event of net undercollections of fuel costs. Because the revenue requirement impact of the two matters reconsidered essentially offset each other, the NCUC did not modify its original allowed rate increase of $90.8 million.

4) There are currently pending before the NCUC two general rate proceedings (Docket Nos. E-2, Sub 391 and E-2, Sub 416) and three fuel clause proceedings (Docket Nos. E-2, Sub 402; E-2, Sub 411 and E-2, Sub 446) which have been remanded to the NCUC by the North Carolina Supreme Court and Court of Appeals. The remanded cases relate to NCUC orders issued between October 1980 and February 1982 which were appealed through the Courts by various parties to those proceedings. In the fall of 1983, the Courts determined that the fuel clause statute, as it existed at the time of the proceedings in question, did not permit recovery of any portion of purchased power costs in a fuel clause proceeding and that the reasonableness and proper level of all fuel costs, including purchased power, should be reviewed in a general rate proceeding. The NCUC was ordered to conduct a hearing in the nature of a general rate case to determine if rates during the periods covered by those proceedings were reasonable and proper and to adjust current rates as necessary to true-up any discrepancy. The Company does not expect the remand to result in any material adjustment in rates.

5) Permanent retail rate increases since 1981 are as follows:

Effective Date	State	Approximate Increase in Jurisdictional Revenues Granted	Annualized Increased Revenues Based On Test Year Level of Sales: Requested	Granted
5/1/81	South Carolina	11%	$ 27,500,000	$ 15,339,000
12/15/81	North Carolina	13	151,432,000	119,197,000
6/1/82	South Carolina	14	40,341,000	24,958,000
9/24/82	North Carolina	[a]1	173,700,000	[a]8,784,000
[b]9/19/83	North Carolina	8	164,913,000	90,855,000
[b]10/7/83	South Carolina	15	44,040,000	34,900,000

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[a]Based upon rates in effect at the date of the order, rather than rates in effect at the date of the application.

[b]The rates of return granted to the Company are as follows:

North Carolina (test year ended September 30, 1982)

Capital Structure	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	49.5%	9.59%	4.75%
Preferred Stock	12.5	8.96	1.12
Common Equity	38.0	14.50	5.51
Rate of Return			11.38%

South Carolina (test year ended December 31, 1982)

Capital Structure	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	47.63%	9.49%	4.52%
Preferred Stock	13.04	8.96	1.17
Common Equity	39.33	14.50	5.70
Rate of Return			11.39%

6) The average time lag between the filing of an application for a general rate increase and final commission action on such rate increase has been 7 months in North Carolina and 13 months in South Carolina. Legislation adopted in South Carolina in 1983 will reduce the time lag to approximately 6 months in that state. (See paragraph 9 below.)

7) In June 1982, the North Carolina General Assembly revised the fuel clause procedure of the NCUC to require the NCUC to set base fuel costs in general rate cases and to authorize the NCUC to hold additional hearings no more frequently than once every 12 months to determine whether a rider should be added to base fuel rates to

reflect increases or decreases in the cost of fuel and the fuel cost component of purchased power. The revision requires that any fuel adjustment which is allowed be based on fuel expenses prudently incurred under efficient management and economic operation. Prior to the revision, rates were adjusted three times a year to reflect actual changes in the cost of fuel and purchased power. The NCUC held hearings in 1983 in a rulemaking proceeding (Docket No. E-100, Sub 47) to establish rules to implement the new fuel adjustment statute. The NCUC has proposed rules for comment which would require review of fuel costs at least once every 12 months but set forth no specific methodology for calculating those costs. The North Carolina General Assembly also directed the NCUC to determine the need for the fuel clause procedure and to report its findings in the next legislative session. The NCUC established Docket No. E-100, Sub 48, for the purpose of investigating the need and justification for electric utility fuel charge adjustments. A hearing was held in February 1984. The Company cannot predict the outcome of these matters.

8) In June 1982, the North Carolina General Assembly also revised the procedure with respect to CWIP to permit the inclusion of CWIP in the rate base only to the extent the NCUC considers the inclusion to be in the public interest and necessary to the financial stability of the the utility. The NCUC has instituted a separate generic rulemaking proceeding (Docket No. M-100, Sub 95) with respect to the CWIP issue. The Company is unable to predict the outcome of this proceeding.

9) In 1983, the South Carolina General Assembly adopted legislation affecting electric utilities operating in South Carolina, including the following provisions: 1) The existence of the SCPSC was reauthorized for six years. 2) The SCPSC was directed to rule on proposed rate changes by electric utilities within six months of the filing of the proposed changes. This period may be extended an additional five days upon a showing by the SCPSC that they are unable to issue the order within the prescribed time due to circumstances beyond their reasonable control. 3) The electric utility may not place into effect proposed changes in rates until the rates have been approved by the SCPSC. Failure of the SCPSC to act within the prescribed time shall constitute approval of the proposed rate changes by the SCPSC. 4) The electric utility may put proposed rate changes in effect under bond pending appeal of a rate order issued by the SCPSC. 5) The electric utility must give not less than thirty days advance notice of its intention to file proposed changes in its rates. 6) The electric utility may not request a rate increase within twelve months of a prior filing for a rate increase. 7) The fuel clause procedure which had been in effect pursuant to SCPSC rule was enacted without substantive change.

10) The Company is continuing its intensive conservation and load management programs designed to reduce the 1995 summer peak demand by 1750 MW. Several portions of such programs have been implemented. The Company currently offers time-of-day rates to all of its retail customers, financial incentives for utility control of water heaters and air conditioners to residential customers in certain metropolitan areas on the Company system, loans to its residential customers at 6 percent interest to install insulation and a rate discount to residential customers who have minimized heat loss from their homes. The Company is actively pursuing cogeneration with its industrial customers and has rates available for the purchase of power from customer-owned facilities, as well as stand-by service for customers using their generation equipment to reduce load.

Wholesale Rate Matters

1) In June 1977, the Company filed an application (Docket No. ER77-485) with the FERC for authority to increase rates for wholesale customers to produce an estimated $26 million annual increase over rates subsequently agreed to in the then pending (Docket No. ER76-495) rate case. These rates were placed into effect on December 29, 1977, subject to refund with interest, and remained in effect until superseded by new rates. In December 1980, the Company filed a Settlement Agreement in this case, which allowed the Company to retain approximately $15 million annually of the requested increase, and, in January 1981, refunds with interest thereon were made in the amount of approximately $29.5 million. The Settlement Agreement was approved by the FERC; however, under the terms of this agreement, several issues were reserved for decision by the FERC, including tax normalization and adjustment for spent nuclear fuel storage and disposal costs. The tax normalization issue has been decided in favor of the Company. With respect to the fuel adjustment issue, the Company's wholesale customers filed a complaint with the FERC in September 1977, charging that the Company was improperly applying the fuel adjustment clause by including the cost of nuclear fuel storage and disposal in the adjustment. These customers requested relief from imposition of the charges and a refund of such amounts collected under the clause by the Company. In November 1981, a FERC order was issued which decided the September 1977 complaint in favor of the Company's wholesale customers. The order also decided one of the reserved issues from Docket No. ER77-485 in favor of the Company's wholesale customers. The Company's motion for rehearing was denied. In August, 1982, the Company refunded $15.3 million to its wholesale customers as a result of this proceeding. The Company filed a Petition for Review with the United States Court of Appeals for the District of Columbia Circuit. On August 26, 1983 the United States Court of Appeals for the District of Columbia Circuit rendered its decision that the FERC had not adequately stated the reasons for its ruling in light of the record and remanded the case back to the FERC for further analysis and consideration. On March 7, 1984 FERC issued a remand order reversing its previous disallowance of spent nuclear fuel storage and disposal costs in the Company's rates. Since the 30-day time for appeal of the March 7, 1984 remand order has not expired, the Company cannot predict the outcome of this matter. However, since refunds have already been made in these dockets, any adverse determination of this issue is not expected to have a significant impact on the Company's overall financial condition or results of operations.

2) In February 1979, the Court of Appeals for the District of Columbia Circuit remanded to the FERC for reconsideration Order 530B which had authorized comprehensive interperiod tax allocation (normalization) for wholesale ratemaking. The case considered by the Court was the review of a rulemaking procedure rather than a specific rate case. On remand, the FERC approved a rule in February 1982 requiring normalization (Order No. 144-A). That rule was appealed to the Court by a group of municipal and cooperative electric systems. In addition, certain wholesale customers of the Company appealed to the same Court the FERC's approval of tax normalization in connection with one of the Company's rate cases. On May 31, 1983, the United States Court of Appeals for the District of Columbia Circuit upheld the FERC rule requiring tax normalization and the application of such rule in connection with one of the Company's wholesale rate cases. The United States Court of Appeals for the District of Columbia Circuit denied the Petition for Rehearing filed by a group of municipal and cooperative electrical systems on July 15, 1983. No party filed a timely appeal.

3) During 1982 the FERC approved settlement agreements between the Company and its wholesale customers with respect to rate increase requests of $30.8 million and

$30.5 million filed in April 1980 (Docket No. ER80-344) and June 1981 (Docket No. ER81-538), respectively. Pursuant to these settlement agreements the Company was granted rate increases of $23 million and $19.8 million, respectively. Both settlement agreements left open the tax normalization and spent nuclear fuel adjustment issues. The tax normalization issue was decided in favor of the Company. On March 7, 1984 FERC issued a remand order reversing its previous disallowance of spent nuclear fuel storage and disposal costs in the Company's rates. Since the 30-day time for appeal of the March 7, 1984 remand order has not expired, the Company cannot predict the outcome of this matter. However, any adverse determination of this issue is not expected to have a significant impact on the Company's overall financial condition or results of operations.

4) On September 26, 1983, the Company filed an application (Docket No. ER83-765) with the FERC for authority to increase rates for wholesale customers by 14.5% to produce an additional $30.7 million annually. The increase is requested to become effective in two phases: Phase I — $19.0 million or 9.0% increase effective on November 26, 1983; and Phase II — $11.7 million or 5.5% increase effective November 27, 1983. The requested rate of return on common equity is 15.5% based on a common equity ratio to total capitalization of 39.94%. The proposed overall rate of return is 12.11%. The request proposes the inclusion of a total of $70 million of CWIP in the wholesale rate base. The FERC has authorized the Phase I portion of the Company's proposed wholesale rate increase to be effective November 27, 1983, subject to refund. The FERC suspended the Phase II portion for five months to become effective on April 27, 1984, subject to refund. A hearing is scheduled to begin on June 11, 1984. The Company is unable to predict the outcome of this matter.

Generating Capability

1) The Company's major installed generating facilities are shown in the table below:

Plant Location	Unit No.	Year Installed	Primary Fuel	Maximum Dependable Capacity	Net 1983 Station Generation(a) MWH	Fuel Cost(a) (1983 Avg. Mills/KWH)
Asheville (Skyland, N.C.)	1	1964	Coal	198 MW	2,377,595	17.62
	2	1971	Coal	194 MW		
Cape Fear (Moncure, N.C.)	5	1956	Coal	143 MW	1,046,342	18.53
	6	1958	Coal	173 MW		
H. F. Lee (Goldsboro, NC)	1	1952	Coal	79 MW	1,488,115	19.46
	2	1951	Coal	76 MW		
	3	1962	Coal	252 MW		
H. B. Robinson (Hartsville, S.C.)	1	1960	Coal	174 MW	578,475	19.28
	2	1971	Nuclear	665 MW	3,347,522	4.57
Roxboro (Roxboro, N.C.)	1	1966	Coal	385 MW	13,233,756 (c)	20.11
	2	1968	Coal	670 MW		
	3	1973	Coal	707 MW		
	4	1980	Coal	700 MW (b)		
L. V. Sutton (Wilmington, N.C.)	1	1954	Coal	97 MW	1,593,982	21.79
	2	1955	Coal	106 MW		
	3	1972	Coal	410 MW		
Brunswick (Southport, N.C.)	1	1977	Nuclear	790 MW (b)	4,426,995 (c)	4.76
	2	1975	Nuclear	790 MW (b)		
Mayo (Roxboro, N.C.)	1	1983	Coal	705 MW (b)	3,111,583 (c)	21.08

(a) Excluding internal combustion turbines and heat recovery units.
(b) Facilities are jointly owned by the Company and Power Agency, and the capacity shown includes Power Agency's share.
(c) Excludes 445,977 MWH for Roxboro Unit No. 4, 600,521 MWH for Mayo Unit No. 1 and 897,618 MWH for Brunswick Units representing Power Agency's share of Net Station Generation.

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2) The remainder of the Company's capability is composed of 53 smaller fossil, hydro and internal combustion turbine units ranging in size from a .5 MW hydro unit to a 78 MW coal-fired unit. In addition, the Company has short-term agreements for the temporary purchase of power. See "Interconnections With Other Systems."

3) On August 17, 1973, the Company filed an application with the Federal Power Commission (now the Federal Energy Regulatory Commission) for new 50-year licenses for its Walters Hydroelectric Plant. North Carolina Electric Membership Corporation (NCEMC) filed a competing application on August 24, 1974. ElectriCities of North Carolina intervened in both proceedings. On August 5, 1981, ElectriCities withdrew its interventions. The Company and NCEMC on January 25, 1982, jointly requested FERC to hold the pending proceedings in abeyance until further notification from the applicants. An order was entered by FERC on February 4, 1982, staying the proceedings until August 2, 1982. Since that time, orders further staying the proceedings through August 1, 1984 have been issued by FERC. The Company has continued to operate the Walters Hydroelectric Plant under licenses issued from year to year.

4) The Company maintains all of its properties in good operating condition in accordance with sound management practices. The average life expectancy for ratemaking and accounting purposes of the Company's generating facilities (excluding internal combustion turbine units) is 35 years for fossil units installed prior to 1966, 30 years for fossil units installed thereafter and 25 years for nuclear units. Of the total installed generating capability of 8,750 MW, 60% is coal, 26% is nuclear, 2% is hydro and 12% is fired by other fuels including No. 2 oil, natural gas and propane.

5) Total System generation (including Power Agency's share) by energy source for the years 1981 through 1984 is set forth below:

	1981	1982	1983	1984*
Coal	69%	75%	72%	80%
Nuclear	29	23	25	17
Hydro	1	2	2	2
Other	1	-	1	1

*Estimated

Environmental Matters

1) To comply with state and federal environmental laws and regulations the Company has included in its construction program approximately $103 million for Mayo Unit No. 2 and approximately $10 million for Harris Unit No. 1. In addition, approximately $38 million is estimated to be required during 1984 to 1986 for necessary modifications to comply with pollution control laws and regulations at the Company's existing facilities. Those costs which are expected to be incurred during 1984 to 1986 are included under "Construction Program."

2) Several proposals on acid deposition have been introduced in the United States Congress. Some of the proposals being considered could result in increasing costs for low sulfur coal and/or in a requirement to add costly sulfur dioxide removal equipment to existing plants or plants under construction. The Company cannot predict the outcome of this matter.

3) Pursuant to regulations adopted by the United States Environmental Protection Agency (EPA) under the Clean Air Act and by agencies of North Carolina and South Carolina under similar state statutory authority, fossil generating units are subject to stringent emission limitations and other requirements, primarily for the control of

particulate matter and sulfur dioxide. These regulations are subject to periodic review and approval by the EPA. The EPA has also promulgated "Standards of Performance for New Stationary Sources" which establish specific emission limitations for particulates, sulfur dioxide and nitrogen oxides emitted from power plants on which construction commenced after August 1971 including the Mayo Units and, pursuant to the EPA's interpretation of applicable regulations, Roxboro Unit No. 4. Compliance with these new source standards of performance for sulfur dioxide of 1.2 lbs/MBTU in North Carolina and South Carolina requires coal with an average sulfur content of approximately 0.7% at 12,000 BTU's per pound. The Company has the necessary coal contracts to meet these standards of performance for Roxboro Unit No. 4 and the Mayo Units. Even more stringent limitations are applicable to fossil plants commencing construction subsequent to September 18, 1978. Compliance with the latter regulations will require the installation of sulfur dioxide removal equipment on future fossil plants and may require the installation of such equipment on Mayo Unit No. 2, as well as compliance with more stringent NOx and particulate emission limitations due to changes in its projected in-service date. New power plants including Mayo Units 1 and 2 are also subject to stringent emission regulations relating to the prevention of significant deterioration (PSD) of air quality. If the PSD permit to construct Mayo Unit No. 2 is at any time found to have expired due to changes in its in-service date, a new PSD permit would be required which could require sulfur removal equipment as best available control technology. The Company believes that its PSD permit is valid at the present time. However, if construction is deemed to have been suspended for more than 18 months, an extension pursuant to the PSD regulations may be required. The Company cannot predict the outcome of this matter.

4) Emissions of particulate matter from fossil plants in North Carolina must meet two standards. One standard controls visible emissions by limiting the opacity of emissions from the plant stack. The other standard limits the pounds of particulate matter actually emitted. In order to achieve compliance with particulate emission limitations by existing units, electrostatic precipitators have been installed at all of the Company's coal-fired units (except Cape Fear Units Nos. 3 and 4 which are not currently utilized).

5) On January 13, 1983, the North Carolina Environmental Management Commission (EMC) adopted new particulate emission standards for fossil plants that (1) modified unit specific instantaneous maximum allowable mass emission rates for each existing generating unit and (2) introduced stringent additional annual emission limits on particulate matter emitted. The annual emission limits are expressed in tons of particulate matter and must be met on a rolling 365-day basis. The Company anticipates that it will be able to comply with the maximum allowable instantaneous emission limitations. However, the Company has advised the Division of Environmental Management (DEM) that Roxboro Units Nos. 1 and 3, Weatherspoon Unit No. 3 and Cape Fear Unit No. 6 would be unable to meet their plant specific annual emission limits at current emission levels. In the event the Company is unable to comply with the new limitations, it is uncertain what action, if any, the State may take. At its February 1984 meeting, the EMC temporarily deferred any enforcement action and the Company has executed a Special Order by Consent which 1) suspends the annual particulate emission limits for the units identified above until the EMC completes a full review of the regulation and 2) specifies schedules of tests and evaluations for these four units through December 1984 which will provide further information on precipitator performance. The Order will be presented to the EMC for approval at its April 1984 meeting. The EMC has previously stated that it intends to review the new annual emission limitations after they

have been in effect for a period of time and additional data has been gathered on the ability of utility boilers to comply. Adjustments in the standards may be considered. The annual limit may be made more stringent, and limitations may be imposed during start-up and shut-down periods now excluded from regulation. The Company cannot predict what impact additional limitations would have on the Company but they could be significant. The Company cannot predict the outcome of this matter.

6) By notice dated December 2., 1983, EPA has proposed disapproval of that portion of the North Carolina State Implementation Plan (SIP) adopted on January 13, 1983 governing startups, shutdowns, and malfunctions of air emitting sources. If, following receipt of public comments, the EPA finally disapproves that portion of the SIP, the Company may be in technical violation of federal emission standards for particulates during startups and shutdowns. Emission standards cannot be met by large utility boilers during startup and shutdown periods because electrostatic precipitators cannot be energized when the temperature of combustion gases is below dew point without adversely affecting precipitator performance.

7) The Company meets the current North Carolina sulfur dioxide emission limitation of 2.3 lbs/MBTU at its existing plants by burning coal with an average sulfur content of 1.4% or less at approximately 12,500 BTU's per pound. Environmental standards for sulfur dioxide of 3.5 lbs/MBTU in South Carolina can be met by burning coal with an average sulfur content of 2.1% or less at approximately 12,000 BTU's per pound. In the event the regulatory agencies having jurisdiction object to the Company's practice of using coal of differing quality to achieve overall compliance with sulfur dioxide emission limitations, the Company's fuel costs could increase substantially. If the Company is unable to purchase coal of sufficient quality in the future to comply with sulfur dioxide emission limitations, significant additional costs could be incurred for installation of sulfur dioxide removal equipment.

8) The Federal Clean Water Act prohibits the discharge of pollutants (including heat) except pursuant to the terms and conditions of National Pollutant Discharge Elimination System (NPDES) permits issued by the Administrator of the EPA or the Administrator of approved state programs. Timely permit applications were filed for all of the Company's generating plants and permits for all operating plants were ultimately issued. Although many of these permits expired in the first half of 1980, either renewal permits have been issued or the expired permits have been extended by the timely filing of renewal applications which stay the expiration of the permits. In July 1982 initial NPDES permits were issued for the Harris and Mayo Plants. The renewal NPDES permit for the Robinson Plant was issued and became effective on December 1, 1983. The Brunswick Plant has been issued a renewal NPDES permit. The Brunswick Plant renewal permit requires a reduction of plant intake of circulating water during certain periods of the year in lieu of the installation of cooling towers which were previously required. This reduction of circulating water flow reduces the heat removal capability of the condensers and thus will, during certain seasonal environmental conditions, limit the power level of each unit. Actual hourly power level reductions are estimated to range between 0% and 5% of full power, which could result in an average annual loss of approximately 2% of net capability. At times when the Company's system demand reaches within 200 MW of available generating resources, flow restrictions can be suspended allowing full power operation.

9) Except as noted herein, the Company does not anticipate additional significant costs for compliance with environmental laws and regulations, although additional costs

could be incurred as a result of changes in or more stringent enforcement of existing federal and state laws and regulations or in the event it is found that modifications now planned to meet the requirements of environmental laws and regulations fail to provide the anticipated degree of control.

Nuclear Matters

1) The electric utility industry in general has been experiencing problems in a number of areas relating to the construction and operation of nuclear plants including the effects of inflation upon the cost of operations and upon construction costs; increased costs and licensing delays related to compliance with changing regulatory requirements; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

2) In connection with information resulting from the incident at the Three Mile Island Unit No. 2 located near Harrisburg, Pennsylvania, the Company has implemented and continues to implement changes to systems and procedures at its nuclear plants. The NRC has issued many post-Three Mile Island safety requirements. The scheduled completion dates for many of the early requirements were extended by the NRC beyond 1981 because of problems in procuring adequate equipment and NRC revision of some of the requirements. Implementation schedules for certain of the new NRC requirements, which deal with the habitability of control rooms during radioactive or toxic chemical releases, increased requirements for emergency response facilities and data systems, training program improvements and design reviews of nuclear plant control rooms, now extend beyond 1984 and have been included in the estimated construction expenditures under "Construction Program".

3) The Company's Robinson Unit No. 2, a pressurized water reactor, has experienced deterioration of steam generator tubes as have other similar units. The deterioration has resulted in leaks which have required outages for inspection and plugging of tubes. The Company had planned to replace the Robinson steam generators in 1984 and 1985. Robinson Unit No. 2 was removed from service on January 26, 1984 due to steam generator tube leaks. Inspections and tests indicated that tube corrosion had reached the point where continued operation of the unit prior to replacement of the steam generators was not feasible. The steam generator replacement outage for Robinson Unit No. 2 began on February 6, 1984. The unit is currently expected to be out of service until January 1985. The NRC has issued a license amendment authorizing the replacement. Capital expenditures during 1984 and 1985 for the replacement of the steam generators and associated equipment are estimated to be approximately $93 million (including AFUDC), which has been included in the Company's estimated 1984-1986 construction expenditures. The total cost of the replacement is estimated to be approximately $134 million.

4) Although the Harris Unit under construction is also a pressurized water reactor, it is of a later design and the Company intends to incorporate improvements in the design of the steam generators. These improvements will reduce the likelihood that the problem experienced at Robinson Unit No. 2 will occur at the Harris Plant. Steam generators similar to those to be used in the Harris Plant have, however, experienced

vibration problems which are currently being studied by the vendor. Modifications intended to minimize these problems have been made to the Harris steam generators.

5) The NRC has asked the Company and other utilities which own pressurized water reactors, such as the Company's Robinson Unit No. 2, for information on the ability of the reactor pressure vessels to withstand the effects of thermal shock. Thermal shock is a condition which results from the introduction of cold water into a hot pressurized reactor vessel. If the fracture toughness of the vessel has been reduced sufficiently by extensive irradiation, cracking could result from thermal shock. The NRC believes that older reactor pressure vessels can withstand thermal shock at the present time, but believes that continued operation at full power could reduce the vessel toughness to unacceptable levels before retirement of these plants. The Company's analysis indicated that the Robinson Unit will approach the NRC screening criteria around 1993 based upon the Company's current outage schedule. In December 1983, the NRC advised the Company that it concurred with the analysis that the Robinson Unit No. 2 would not reach the NRC screening criteria prior to 1993. Plant specific analysis was also undertaken by the Company to determine if the unit can exceed or avoid reaching the NRC screening criteria without plant modifications and to define the nature of any modifications that may be required prior to the end of the operating life of the Unit to avoid the risk of reactor pressure vessel cracking from thermal shock. The results of plant specific analyses indicate that with planned fuel modifications the unit can operate to the expiration of the operating license (2007) without reaching the NRC screening criteria. The Company presented the results of the plant specific analysis in a report to the NRC in 1983 and requested NRC concurrence with the report. The NRC is in the process of reviewing the Company's report. The Company cannot predict the outcome of this matter. The Company is also participating in separate plant specific research programs on the effects of thermal shock sponsored by the NRC and the Electric Power Research Institute.

6) Westinghouse units similar to Robinson Unit No. 2 have experienced stress corrosion cracks in low-pressure turbine disks. In 1978, four disks at Robinson Unit No. 2 were found to have stress corrosion cracks and were replaced. The Company performed an inspection of all remaining Robinson Unit No. 2 low-pressure disks in 1980 and no cracks were found. The Company will monitor the turbine in the future for any recurrence of the cracking problem. A turbine missile analysis was performed for Robinson Unit No. 2 when the plant was licensed and is summarized in the Final Safety Analysis Report for the Unit. Findings by the turbine manufacturer indicate that the initial missile analysis on this Unit did not account for stress corrosion cracking and the non-symmetrical impact of disk fragments that could change the analysis results. The Company is awaiting NRC approval of the turbine manufacturer's analysis methodology before proceeding with further evaluations.

7) An NRC order authorizing an increase in power from 2200 to 2300 MW(t) at Robinson Unit No. 2, which found the unit acceptable environmentally, is subject to review regarding radon releases. The Company is unable to predict what effect, if any, this matter may have on the operation of Robinson Unit No. 2.

8) General Electric Company has informed the Company that stress corrosion cracks in low-pressure turbine disks have been found in three General Electric turbines similar to the Brunswick Units Nos. 1 and 2 turbines. Inspection of the Brunswick Unit No. 2 turbine was completed in June 1982, in conjunction with the scheduled maintenance outage. The inspection of the Brunswick Unit No. 1 turbine was completed in March 1983

during a scheduled refueling and maintenance outage. No repairs were required as a result of these inspections; however, the inspection results indicate that the disks should be monitored by future inspections.

9) The Company has been required by the NRC to modify the augmented off-gas system at the Brunswick Plant. The system provides a reduction in releases of radioactive gases to the environment. The modifications to the augmented off-gas system at Brunswick Unit No. 1 were completed during the scheduled refueling and maintenance outage which ended in August 1983. In December 1983, the NRC granted the Company's request to defer the final modifications to the augmented off-gas system at Brunswick Unit No. 2 until the spring of 1984. The Company plans to make these final modifications to Brunswick Unit No. 2 during the scheduled maintenance outage which began in March 1984.

10) The Company is in the process of replacing the condenser tubes in the Brunswick Units to reduce the potential for tube leaks which interfere with the chemistry limits in the primary system. Replacement of the condenser tubes on Brunswick Unit No. 1 was completed in the spring of 1983. Replacement of the Brunswick Unit No. 2 condenser tubes is currently planned during the scheduled maintenance outage which began in March 1984.

11) On December 2, 1981, the NRC published final regulations establishing interim requirements related to hydrogen control at operating nuclear power plants pursuant to which the Company is required to make certain modifications to the Brunswick Units. The Company has sought review of the regulations by the United States Court of Appeals for the Fourth Circuit. Pursuant to the Company's request for exemption, the NRC granted the Company relief to June 1984 from the schedule provisions of the interim requirements. The Company has filed with the NRC a request for exemption from the technical requirements of the regulations. The Company cannot predict the outcome of these proceedings.

12) In July 1982, the Company committed to the NRC to investigate and review its technical specification surveillance requirements at the Brunswick Plant and the management control systems applicable thereto. The administrative procedures for the Brunswick Plant required by its pre-startup commitments to the NRC and surveillance requirements and required valve testing of containment isolation valves were completed in September 1982. The Company has also made post-startup commitments to the NRC with respect to long-term corrective actions which it will undertake to assure timely compliance with technical specification surveillance requirements.

13) In 1982, the NRC notified the Company that the large diameter reactor recirculation system piping in boiling water reactor units such as the Brunswick Units has the potential to crack as a result of intergranular stress corrosion and required an ultrasonic inspection of such piping at boiling water reactor units undergoing a refueling or extended outage prior to January 31, 1983, which included Brunswick Unit No. 1. Some repairs were made on Brunswick Unit No. 1 during the spring of 1983. Additional recirculation piping inspections were performed on Brunswick Unit No. 1 in October 1983 during a scheduled outage. Two of the six welds inspected were found to have indications of cracking and were repaired. The NRC has required that an evaluation be performed to assess the adequacy of the recirculation piping weld inspections performed on Brunswick Unit No. 1 in early 1983 in light of the subsequent upgrade in inspection qualification requirements. Portions of the Brunswick Unit No. 2 piping were inspected in February

1983, and no cracks were found. In November 1983, inspections were conducted on Brunswick Unit No. 2's recirculation piping welds. The results of the inspection showed nineteen welds with indications of cracking. The Company elected to repair eight welds. It was determined that the indications of cracking in the remaining eleven welds were minor and that repair could be safely deferred until the scheduled maintenance outage currently in progress. In December 1983, the NRC approved the Company's actions with regard to the nineteen welds. The NRC issued an order allowing Brunswick Unit No. 2 to return to full power operations. The Company has committed to perform additional inspections of limited scope on Brunswick Unit No. 2 during the 1984 refueling outage and on Brunswick Unit No. 1 in November 1984. The NRC has neither accepted nor rejected these plans at this time. Based on recent industry experience with respect to stress corrosion cracking in recirculation piping and the NRC position that weld overlay repairs are acceptable only for the short-term, the Company has purchased replacement piping for one unit and initiated other preparations to perform the replacement. The extent to which piping may require replacement will depend upon future inspection results. Full recirculation system replacement, if required, could require approximately nine months of outage time per unit and is expected to cost approximately $36 million per unit. (See also "Nuclear Matters", paragraph 16 below for discussion of outage schedule.) The Company cannot predict the outcome of these matters.

14) The Company has pending before the NRC petitions for exemptions for the Brunswick Plant and Robinson Unit No. 2 from certain of the requirements of the NRC's fire protection regulations. With respect to the Brunswick Plant, in July 1983, the NRC granted certain of the exemptions which the Company had requested and denied the remaining requests. With the NRC's concurrence, the Company is now performing an analysis to develop alternative measures to those originally proposed which the Company can take in order to meet the requirements of the regulations. The Company expects to submit the results of its analysis in May 1984 for NRC review and approval. With respect to Robinson Unit No. 2, in November 1983, the NRC granted certain of the exemptions the Company had requested. Two of the Company's exemption requests with respect to Robinson Unit No. 2 are still pending.

15) In June 1981, the Company petitioned for hearings on NRC orders which required upgrading the environmental qualification of electrical equipment in the Company's nuclear units by June 30, 1982. The NRC suspended the June 30, 1982 deadline pending promulgation of regulations. The suspension of the June 30, 1982 deadline was challenged in the United States Court of Appeals for the District of Columbia Circuit, and the Company intervened in that proceeding. In January 1983, the NRC promulgated regulations pursuant to which the deadline for each unit was changed to the end of the second refueling outage after March 31, 1982 or by March 31, 1985, whichever is earlier. Petitions for review of these regulations have been filed in the Court of Appeals for the District of Columbia Circuit. As a result of the promulgation by the NRC of regulations changing the deadline, the Company withdrew its June 1981 petition. The Court of Appeals for the District of Columbia Circuit has remanded on procedural grounds to the NRC the NRC's regulation suspending the June 30, 1982 deadline for equipment qualification which the NRC issued pending promulgation of the final rule. In March 1984, in response to the Court's decision, the NRC issued for public comment a new proposed rule by which it would suspend the June 30, 1982 deadline. The Company plans to complete equipment qualification modifications on Brunswick Unit No. 1 during an outage currently scheduled to begin in the spring of 1985. Based on the current regulatory requirements, completion of equipment qualification modifications is

required during the Brunswick Unit No. 2 scheduled outage which began in March 1984. The Company plans to seek regulatory relief to extend the completion date for Brunswick Unit No. 2 to November 1985 as a minimum, and possibly to the spring of 1986. Requests for deferral to the spring of 1986 would be based on coordinating equipment qualification work with recirculation pipe replacement. If regulatory relief is not granted, Brunswick Unit No. 2 would be delayed in returning to service from the March 1984 outage. In addition, if regulatory relief to extend the completion to the spring of 1986 is requested and not granted, an earlier than currently planned outage would be required for Brunswick Unit No. 2. The Company cannot predict the outcome of the request for schedule relief.

16) The Company's nuclear units will be periodically removed from service to accommodate certain major modifications, normal refueling and maintenance and other activities. Currently, Brunswick Unit No. 1 is scheduled for eleven weeks of outage time in 1984 for maintenance, tests, and recirculation piping inspections, and an outage of approximately 46 weeks duration, beginning in the spring of 1985 for refueling, modifications related to the environmental qualification of electrical equipment, maintenance, and replacement of the recirculation piping, if required. No additional outages are currently planned for Brunswick Unit No. 1 in 1986. In March 1984, Brunswick Unit No. 2 began a scheduled outage of approximately 36 weeks for condenser tube replacement, replacement of the augmented off-gas system, refueling, and other maintenance activities. Currently, no outage is scheduled for Brunswick Unit No. 2 in 1985. Brunswick Unit No. 2 is scheduled for an outage of approximately 46 weeks, beginning in the spring of 1986, for refueling, modifications related to the environmental qualification of electrical equipment, maintenance, and replacement of the recirculation piping, if required. If the NRC does not grant the Company's request for schedule relief for completing equipment qualification work beyond November 1985, it may be necessary to schedule an outage for Brunswick Unit No. 2 in 1985. Robinson Unit No. 2 is currently out of service for steam generator replacement, refueling, and other maintenance and modifications. The unit is currently expected to be out of service until January 1985. Robinson Unit No. 2 is scheduled for a refueling and maintenance outage of approximately 15 weeks in early 1986. Capital expenditures for modifications at the nuclear units during the 1984-1986 period including replacement of the Robinson Unit No. 2 steam generator and including replacement of the Brunswick Plant recirculation piping, if required, are expected to total approximately $403 million (including AFUDC). These scheduled outages, including estimated costs, outage durations and activities planned, are based upon the NRC granting the Company's planned request for relief from the current regulatory schedule for modifications related to the environmental qualification of electrical equipment at the Brunswick Plant and are subject to continuing review and revision due to additional or revised regulatory requirements or other changing conditions or circumstances. The nuclear units may also experience unscheduled outages from time to time due to circumstances or conditions the Company is unable to predict at this time. If additional regulatory requirements are imposed or the NRC does not concur in the Company's proposed modifications or scheduling of such proposed modifications, the schedule may be changed and/or required outage time and estimated expenditures may be increased.

17) In January 1978, a construction permit was issued by the NRC for the construction of the Harris Plant. The construction permit is subje[illegible]o further review by the Atomic Safety and Licensing Appeal Board (ASLAB) in conjun[illegible] with an industry-wide review of the environmental effects of radon releases asso[illegible]e[illegible] with the nuclear fuel cycle. The Company filed with the NRC an amended application for operating

licenses for Harris Units Nos. 1 and 2. Due to the cancellation of Harris Unit No. 2, however, the Company plans to file in early 1984 an amended application for an operating license for Harris Unit No. 1 only. Interventions in the operating license proceeding have been allowed and the case is being vigorously contested. The hearing will be conducted in phases with environmental and security issues scheduled to be heard in June 1984; management capability and safety issues in September and October 1984; and emergency planning issues in February 1985. At present approximately twenty-one issues are scheduled to be litigated in these hearings. The Company expects that the intervenors will seek to litigate numerous emergency planning issues and that they will raise other issues during the course of the proceeding. The NRC Staff has issued a Final Environmental Statement (FES) on the environmental considerations associated with the application for an operating license for the Harris Plant. In the FES, the NRC staff concluded that, from the standpoint of environmental effects and subject to certain ongoing environmental monitoring requirements once the Plant becomes operational, the operating license should be issued. The FES represents conclusions based on environmental matters only and does not constitute the final licensing action. The NRC Staff has issued its Safety Evaluation Report (SER) for the Harris Plant. The SER identified a number of issues which have to be reviewed or resolved. The NRC Staff has determined that upon favorable resolution of these issues, it will be able to conclude that the Harris Plant can be operated by the Company without endangering the health and safety of the public. The Advisory Committee on Reactor Safeguards (ACRS) sent a letter in January 1984 to the NRC stating that the ACRS found no reason to believe that the issues identified in the SER will be especially difficult to resolve. The ACRS further stated that, if due regard is given to the items mentioned in the letter, and subject to satisfactory completion of construction, staffing and preoperational testing, there is reasonable assurance that the Harris Plant can be operated at full power without undue risk to the health and safety of the public. The Company is unable to predict the outcome of these licensing proceedings.

18) In October 1983, the NRC issued notification to the Atomic Safety and Licensing Boards reviewing applications for operating licenses at a number of plants, including the Company's Harris Plant, of problems with emergency diesel generators manufactured by Transamerican Delaval (TDI) and proposed for use at such plants. TDI diesel generators have experienced a number of equipment failures at several nuclear sites which have made the reliability of these diesel generators suspect. The Company is working with a number of other utilities in attempting to resolve the problems associated with these diesel generators. If these problems are not resolved in a timely manner, the scheduled in-service date of Harris Unit No. 1 could be adversely affected. The Company cannot predict the outcome of this matter. The emergency diesel generators for the Company's Brunswick Units and Robinson Unit No. 2 are manufactured by companies other than TDI.

19) In January 1983, the President signed into law the Nuclear Waste Policy Act which provides the framework for development by the federal government of interim storage and permanent disposal facilities for radioactive waste materials. The Act promotes increased usage of interim storage at existing nuclear plants. The Company will continue to maximize the usage of spent fuel storage capability within its own facilities for as long as feasible. Assuming normal operating and refueling schedules, sufficient space is currently available to operate the Brunswick Units through 1984 and Robinson Unit No. 2 through 1987 with full core discharge capability. The Company is in the process of increasing the spent fuel storage capacity at these plants. The modification to the Robinson Unit No. 2 spent fuel storage facilities was completed in

November 1983. In December 1983, the NRC approved the Company's request to increase the spent fuel storage capacity at the Brunswick Plant. The Brunswick Plant modifications are scheduled to be completed in 1985. Such modifications will permit operations until the early 1990's. By the time additional storage is required, the Harris Plant spent fuel storage facilities are expected to be licensed and may provide storage space for spent fuel generated on the Company system through the 1990's. As required by the Act, the Company entered into a contract with the Department of Energy (DOE) for disposal of spent nuclear fuel. The contract includes a provision requiring the Company to make payments to the DOE for disposal costs. The Company's liability for disposal of nuclear fuel wastes attributable to generation through April 6, 1983 is $97.7 million, of which Power Agency's share is approximately $9.7 million. As of December 31, 1983 the Company had collected through customer rates and included in a reserve for disposal of nuclear fuel approximately $58.7 million of its $88 million net obligations. Pursuant to the regulations, the Company has until June of 1985 to select among the several different payment options. Disposal costs incurred after April 6, 1983 are based upon actual nuclear generation and are paid on a quarterly basis. These costs are expected to be approximately $10 million annually based on the present level of operations and the present disposal fee per KWH of nuclear generation. (Disposal fees may be reviewed annually by the DOE and adjusted, if necessary.) The Company's disposal costs are expected to increase when Harris Unit No. 1 becomes operational. Because of contingencies in the Act, the Company cannot predict at this time whether the federal government will be able to provide interim storage or permanent disposal repositories for spent fuel and/or high level radioactive waste materials.

20) On March 13, 1984, the NRC Staff proposed a $30,000 civil penalty against the Company for alleged violation of NRC requirements at the Robinson Plant. The penalty was proposed for alleged failure of a Company employee and a contractor employee to follow certain technical specifications requirements and radiological and administrative controls upon entering a high radiation area. The alleged violation could have — but did not — result in a worker being exposed to radiation in excess of permissible limits. The NRC Staff reduced the amount of the proposed fine by 25% to $30,000 because of the Company's prompt reporting and investigation of the event and its decisive action to prevent a recurrence. The Company has 30 days from the date of the notice in which to respond.

21) The Company may incur increased construction and operating expenditures as a result of the foregoing matters and, during periods when any of the Company's nuclear units are shut down, system power resources could become inadequate.

Fossil Fuel Supply

1) The Company has intermediate and long-term agreements from which it expects to receive approximately 77% of its coal requirements in 1984. Over the next ten years, the Company expects to receive approximately 73% of its coal requirements from intermediate and long-term agreements. These agreements have expiration dates ranging from 1984 to 2006. During 1982 and 1983, the Company obtained approximately 98% (9,400,000 tons) and 88% (9,024,000 tons), respectively, of its coal requirements from intermediate and long-term agreements. The Company purchased approximately 629,000 tons of coal in the spot market during 1982 and 958,000 tons during 1983. The Company's contract coal purchase prices during 1983 ranged from approximately $30.20 to $46.15 per ton (F.O.B. mine). During 1983, the Company's spot market purchase prices ranged from approximately $18.51 to $24.92 per ton (F.O.B. mine).

2) The average cost to the Company of coal burned for the years shown is as follows:

Year	$/ton	¢/Million BTU
1979	33.64	138
1980	38.75	157
1981	42.55	173
1982	47.22	192
1983	47.89	192

3) During 1983, the Company maintained from 69 to 94 days supply of coal, based on anticipated burn rate.

4) In 1974, the Company entered into agreements with Pickands Mather & Company (PM), a firm engaged in owning, operating and managing mineral properties, to develop two adjacent deep coal mines in Pike County, Kentucky, with an aggregate capacity of two million tons of coal per year. Studies made on behalf of the Company and PM in 1974 and 1975 by Paul Weir Company Incorporated, Chicago, Illinois, independent mining consultants, estimated that the property contained not less than 43.6 million tons of mineable and recoverable coal with an average of 12,800 BTU's per pound and an average sulfur content of 0.58%. The Company and PM formed Leslie Coal Mining Company (Leslie) and McInnes Coal Mining Company (McInnes), both 80% owned subsidiaries of the Company, to develop the two mines. The Company entered into coal purchase contracts with each subsidiary for 80% of the production until the economically mineable coal reserves are exhausted. PM contracted to receive the remaining 20% of production. In 1983, the Company charged $49.9 million to other operation expense for possible losses on its investment in the mines. On November 29, 1983, the Company acquired the 20 percent interests of PM in Leslie and McInnes. Operations at the mines have been suspended since February 1983 because of reduced demand for coal in the utility and industrial markets. At the present time, the Company is pursuing a course of action to sell the mines.

5) Fossil fuels, including natural gas, oil and coal, have been, or are purported to be, subject to allocation by the Department of Energy under various federal laws and executive orders. Although supplies to date have been adequate, such an allocation program could affect the ability of the Company to satisfy its requirements for oil and gas used as fuel in internal combustion turbine units, oil used as fuel for startup, regulation and testing of coal-fired units and for coal and oil used as boiler fuel.

6) The Company uses No. 2 oil primarily for its internal combustion turbine units for emergency backup and peaking purposes. The Company burned approximately 9.9 million and 13.5 million gallons of No. 2 oil during 1982 and 1983, respectively. The Company has fuel oil supply contracts for its normal requirements. In the event base-load capacity is unavailable during periods of high demand, the Company may increase the use of its internal combustion turbine units, thereby increasing oil consumption. The Company intends to meet any additional requirements for fuel oil through additional contract purchases or purchases in the spot market. There can be no assurance that adequate supplies of oil will be available to meet the Company's requirements. To reduce the Company's vulnerability to dislocations in the oil market, seven internal combustion turbine units with a generating capacity of 364 MW have been converted to burn either propane or No. 2 oil. In addition, twelve internal combustion turbine units with a generating capacity of 425 MW can burn natural gas when available. Over the last

five years, No. 2 oil accounted for 3.1% of the Company's total fuel cost. In 1983, No. 2 oil accounted for 2.1% of total fuel costs.

7) The availability and cost of fossil fuel could be adversely affected by energy legislation enacted by Congress, coal allocation, the failure of coal production to meet demand, labor unrest, and the production, pricing and embargo policies of foreign countries.

Nuclear Fuel Supply

1) The nuclear fuel cycle requires the mining and milling of uranium ore to provide uranium concentrate (U_3O_8), the conversion of U_3O_8 to uranium hexafluoride (UF_6), enrichment of the UF_6 and fabrication of the enriched uranium into fuel assemblies. The Company has on hand or has contracted for raw materials and services for Robinson Unit No. 2 and the Brunswick and Harris Units through the years shown below:

Unit	Estimated in-service Date	Raw Materials and Services			
		Uranium	Conversion	Enrichment	Fabrication
Robinson No. 2	*	1990	1987	2002	1989
Brunswick No. 1	*	1989	1987	2002	1993
Brunswick No. 2	*	1990	1987	2002	1989
Harris No. 1	1986	1990	1987	2002	1986

*In commercial operation.

2) These contracts are expected to supply the necessary nuclear fuel to operate Robinson Unit No. 2 through 1988, Brunswick Unit No. 1 through 1988, Brunswick Unit No. 2 through 1988 and Harris Unit No. 1 through 1987. The Company expects to meet its U_3O_8 requirements through the years shown above from inventory on hand and amounts received under contract. Additional supplies of U_3O_8 are currently available in the uranium spot market. The Company does not expect to have difficulty obtaining U_3O_8 and the services necessary for its conversion, enrichment and fabrication into nuclear fuel for years later than those shown above.

3) For a discussion of the Company's plans with respect to spent fuel storage, see "Nuclear Matters".

Interconnections With Other Systems

1) The Company's facilities in Asheville and vicinity are integrated into the total system through the facilities of Duke Power Company (Duke) via interconnection agreements that permit transfer of power to and from the Asheville area. The Company also has interconnections with the Tennessee Valley Authority (TVA), Virginia Electric and Power Company (VEPCO), South Carolina Electric and Gas Company (SCE&G), South Carolina Public Sevice Authority (SCPSA) and Yadkin, Inc. Major interconnections include 230 kV ties with SCE&G and SCPSA and both 230 kV and 500 kV ties with Duke and VEPCO.

2) The Company has interchange agreements with Appalachian Power Company (APCO), Duke, SCPSA, SCE&G, TVA and VEPCO which provide for the purchase of

power for daily, weekly, monthly or longer periods. Purchases under these agreements may be made due to changes in the in-service dates of new generating units, outages at existing units, or for other reasons.

3) The Company has also reached an agreement with the City of Fayetteville, North Carolina to supply partial requirements service and standby service in case of emergency outage of the City's eight 20 MW internal combustion turbine units, of which five are being used by the City for peak shaving purposes. The agreement also makes capacity from these units available to the Company, subject to certain conditions, when they are not being operated to meet the City's peak shaving requirements.

4) The Virginia-Carolinas Subregion of the Southeastern Electric Reliability Council is made up of the Company, Duke, SCE&G, SCPSA and VEPCO plus the Southeastern Power Administration and Yadkin, Inc. Contractual arrangements among the members in the activities of area, regional and national electric reliability organizations, including the Southeastern Electric Reliability Council and the North American Electric Reliability Council, promotes electric service reliability.

Competition and Franchises

Generally, in municipalities and other areas where the Company provides electric service, no other utility renders such service. The Company is a regulated public utility. The Company holds all necessary franchises to operate in the municipalities and other areas it serves.

Other Matters

1) In August 1977, North Carolina Electric Membership Corporation (NCEMC) and 16 of its 18 members who receive wholesale service from the Company filed an antitrust action in the United States District Court in Greensboro, North Carolina, seeking damages of not less than $50.4 million, before trebling, and injunctive relief requiring the Company to provide wheeling services to NCEMC and to deal with NCEMC in respect of certain other power services. The Company has denied the charges contained in the NCEMC's complaint. In the opinion of General Counsel of the Company, the contentions of NCEMC and its members in this litigation are without merit, and the Company should ultimately prevail. In March 1982, a two-year stay order was entered in this proceeding. The Company and NCEMC have begun negotiations for a possible purchase of a portion of the Company's electric generating capacity by NCEMC. If a sale is concluded, the complaint in this proceeding will be dismissed with prejudice. By consent order, the stay has been extended to June 2, 1984. The Company cannot predict the outcome of this matter.

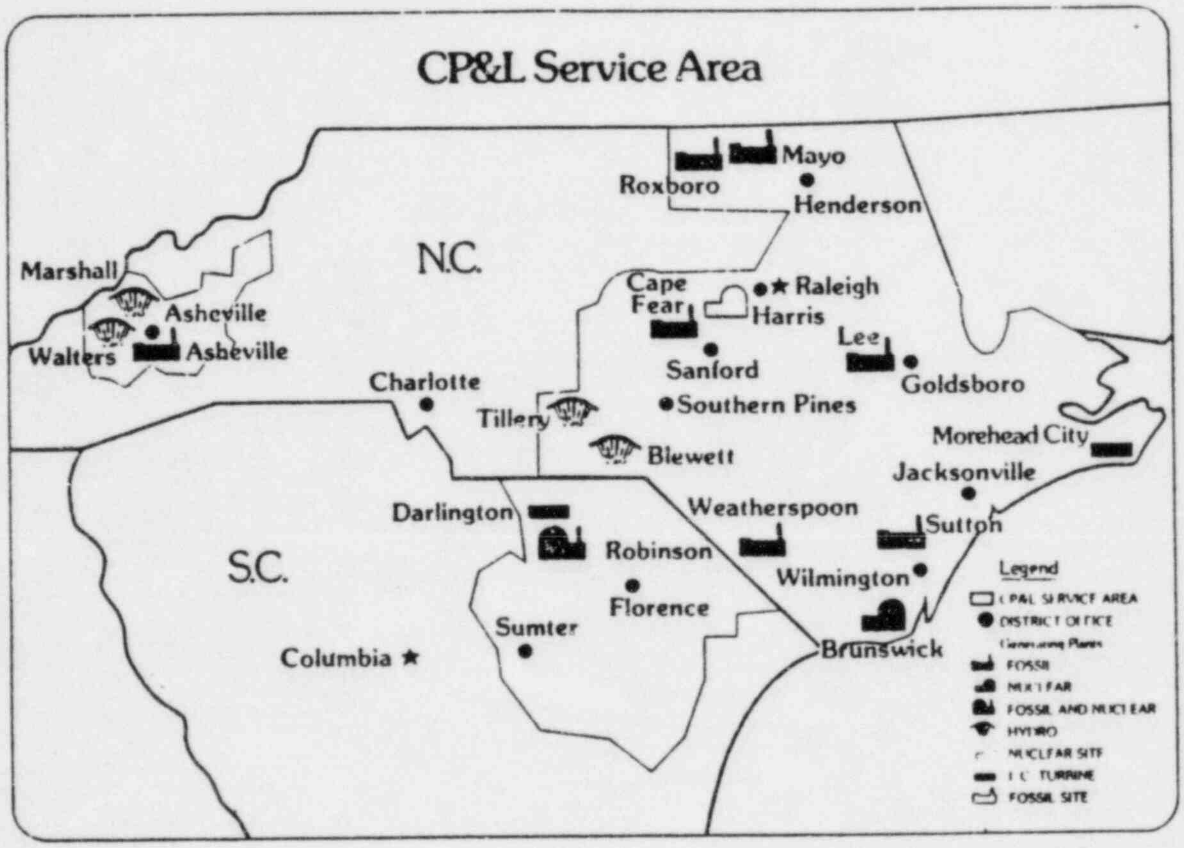
Operating Statistics

	Year Ended December 31.				
	1983	1982	1981	1980	1979
Electric energy supply (millions of kilowatt-hours): (millions of kilowatt-hours):					
Generated – net station output:					
Steam-fossil	23,799	23,079	22,372	22,299	18,336
Steam-nuclear	7,775	6,876	9,344	8,955	10,802
Hydro	816	735	437	680	1,019
Internal combustion turbines	35	23	117	224	146
Total generated	32,425	30,713	32,270	32,158	30,303
Purchased and net interchange	357	1,119	80	25	(3)
Total energy supply (Company share)	32,782	31,832	32,350	32,183	30,300
Power Agency's ownership share	1,529*	361			
Total combined system energy supply	34,311	32,193			
Average fossil fuel cost per million BTU (cents)	196.2	194.8	178.5	163.0	141.8
Average nuclear fuel cost per million BTU (cents)	42.1	35.8	37.2	35.7	35.4
Average total fuel cost (fossil and nuclear) per million BTU (cents)	156.1	155.4	135.1	124.9	100.8
Electric energy sales (millions of kilowatt-hours):					
Residential	8,010	7,647	7,746	7,870	7,195
Commercial	5,546	5,341	5,072	4,935	4,590
Industrial	10,210	9,520	9,968	9,791	9,609
Government and municipal	768	753	823	864	917
Total general business	24,534	23,261	23,609	23,460	22,311
Sales for resale:					
Standard rate schedule:					
Power Agency participants		1,129	2,593	2,561	2,363
Other	4,455	4,253	4,285	4,261	3,994
Power Agency contract requirements	1,896	1,840			
Total electric energy sales	30,885	30,483	30,487	30,282	28,668
Company uses, losses and unaccounted for	1,897	1,349	1,863	1,901	1,632
Total energy supply (Company share)	32,782	31,832	32,350	32,183	30,300
Number of customers(accounts as of end of period):					
Residential	680,581	660,850	647,491	632,209	617,393
Commercial	110,341	106,287	104,919	103,994	102,198
Industrial	4,046	4,010	3,942	3,794	3,625
Government and municipal	919	847	1,117	1,581	1,747
Total general business	795,887	771,994	757,469	741,578	724,963
Resale	33	33	55	55	54
Total customers	795,920	772,027	757,524	741,633	725,017
Operating revenues (in millions):					
Residential	$ 518	$ 474	$ 416	$ 342	$ 293
Commercial	325	302	250	196	172
Industrial	479	434	386	297	268
Government and municipal	41	39	36	30	29
Total general business	1,363	1,249	1,088	865	762
Sales for resale	263	275	245	202	156
Total from energy sales	1,626	1,524	1,333	1,067	918
Miscellaneous	21	14	11	9	8
Total operating revenues	$ 1,647	$ 1,538	$ 1,344	$ 1,076	$ 926
Peak demand of firm load (thousands of kilowatts):					
Total combined system	6,926	6,602	6,402	6,139	5,907
Less Power Agency portion	304*	0**			
Company total peak demand	6,622	6,602	6,402	6,139	5,907
Less sales to Power Agency and Participants	449	637			
Company net peak demand	6,173	5,965	6,402	6,139	5,907
Total capability at end of period (thousands of kilowatts):					
Fossil plants	6,291	5,561	5,519	5,519	4,869
Nuclear plants	2,245	2,245	2,245	2,245	2,245
Hydro plants	214	214	214	214	214
Purchased	75	75	75	75	128
Total combined system capability	8,825	8,095			
Less Power Agency owned portion	494	262			
Add capability purchased from Power Agency	75				
Total Company portion	8,406	7,833	8,053	8,053	7,456

*Net of purchases by the Company from Power Agency.

**The 1982 peak occurred before Power Agency closing on April 21, 1982.

Service Area



ITEM 2. PROPERTIES

For a description of the Company's major generating units, see ITEM 1 - "Generating Capability". See ITEM 1 - "Service Area" for a general outline system map, showing the Company's service area and the location of generating facilities and district offices.

At December 31, 1983, the Company had 5,351 pole miles of transmission lines including 168 miles of 500 KV and 2,444 miles of 230 KV lines, and distribution lines of approximately 36,240 pole miles of overhead lines and approximately 2,604 miles of underground lines. Distribution and transmission substations in service had a transformer capacity of about 29,698,000 KVA in 2,327 transformers. Distribution line transformers numbered 334,452 with an aggregate 11,844,200 KVA capacity.

The properties of the Company are subject to the lien of its Mortgage and Deed of Trust. Otherwise, the Company has good and marketable title with minor exceptions, restrictions and reservations in conveyances, and defects, which are of the nature ordinarily found in properties of similar character and magnitude, to its principal plants and important units, except certain rights-of-way over private property on which are located transmission and distribution lines, title to which can be perfected by condemnation proceedings.

Plant Accounts - During the period January 1, 1979 through December 31, 1983, there was added to the Company's utility plant accounts (including nuclear fuel) \$3,273,221,000, there was retired \$185,678,000 of property other than for the Power Agency sale, there were retirement and other reductions of \$543,157,000 related to the Power Agency sale and there were transfers to other accounts and adjustments for a net decrease of \$381,226,000, resulting in net additions during the period of \$2,163,160,000 or an increase of approximately 62.9%

ITEM 3. LEGAL PROCEEDINGS

Legal and regulatory proceedings are included in the discussion of the Company's business in ITEM 1 and incorporated by reference herein.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders in the fourth quarter of 1983.

EXECUTIVE OFFICERS OF THE REGISTRANT

Information on executive officers is set forth in ITEM 10(b) and incorporated by reference herein.

Part II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

The Company's Common Stock is listed on the New York and Pacific Stock Exchanges. The high and low sales prices per share for the periods indicated, as reported as composite transactions in The Wall Street Journal, and dividends paid are as follows:

1982	High	Low	Dividends Paid
First Quarter	$23	$19 1/2	$.60
Second Quarter	22 3/4	19 5/8	.60
Third Quarter	22 3/4	19	.60
Fourth Quarter	21 7/8	18 7/8	.60

1983	High	Low	Dividends Paid
First Quarter	$23	$20 5/8	$.60
Second Quarter	22 7/8	21 1/2	.60
Third Quarter	23 3/4	20 3/8	.60
Fourth Quarter	25 1/8	21 1/2	.63

As of February 29, 1984, the Company had 103,189 holders of record of Common Stock.

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	1983	1982	1981	1980	1979
	(In Thousands, Except Per Share Figures)				
Operating revenues	$1,647,183	$1,538,165	$1,343,558	$1,075,604	$ 925,910
Net income	239,269	227,147	203,597	161,388	153,244
Earnings for common stock	194,664	182,542	160,937	126,747	124,981
Earnings per common share	$3.21	$3.17	$3.06	$2.73	$3.06
Dividends declared per common share	$2.46	$2.40	$2.32	$2.20	$2.05
Total assets	$5,293,606	$4,950,955	$4,715,835	$4,241,607	$3,647,913
Capitalization:					
Common stock and retained earnings	$1,586,441	$1,462,165	$1,364,692	$1,233,368	$1,045,150
Preference stock	47,900	47,900	47,900	47,900	47,900
Preferred stock - redemption not required	238,118	238,118	238,118	238,118	238,118
Preferred stock - redemption required	214,785	214,743	214,700	175,100	100,000
Long-term debt, net (a)	1,931,672	1,955,824	1,929,448	1,713,467	1,507,690

(a) Long-term debt, net, includes current maturities of $27,554,000, $39,058,000, $46,479,000, $64,122,000 and $21,849,000 for the years 1979-1983, respectively.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

The following discussion and analysis should be considered in conjunction with the relevant sections of ITEM 1, Selected Financial Data in ITEM 6 and the Company's financial statements appearing in ITEM 8.

LIQUIDITY AND CAPITAL RESOURCES

The Company's current construction program normally requires expenditures which are greater than funds generated internally. Sales of long-term securities and short-term borrowings are used to meet needs in excess of such internally generated funds. (See "Construction Program" and "Financing Program" in ITEM 1 for a summary of capital requirements for 1984 through 1986.)

Capital resources for 1981-1983, summarized and restated from the "Statements of Source and Use of Financial Resources" in ITEM 8 to show dividends as a reduction in available resources, were provided as follows:

	(in millions)			
	Total	1983	1982	1981
Operations (less dividends)	$912.6	$398.1	$241.9	$272.6
Sale of generating units	664.1	79.3	584.8	
Financings	818.1	236.5	136.7	444.9
Total	$2,394.8	$713.9	$963.4	$717.5
and utilized as follows:				
Gross property additions and nuclear fuel	$1,948.0	$708.6	$654.7	$584.7
Retirement of long-term debt	346.5	125.7	160.0	60.8
Power Agency trust fund remaining		(153.9)	153.9	
Other working capital increase (decrease), etc.	100.3	33.5	(5.2)	72.0
Total	$2,394.8	$713.9	$963.4	$717.5

The increase (decrease) in capital resources from operations, as compared with the preceding year, resulted from the following changes (in millions):

	1983	1982	1981
Net Income	$ 12.1	$ 23.6	$ 42.2
Dividends	(11.5)	(17.3)	(26.7)
Deferred income taxes and investment tax credits	66.9	(23.5)	52.5
Depreciation and amortization	27.8	(8.8)	24.2
Provision for coal mine losses	49.9		
Deferred income taxes credited to property accounts	11.0	(4.7)	(3.7)
Net increase (decrease) in resources from operations	$156.2	$(30.7)	$ 88.5

The increase in resources from operations in 1983 resulted principally from (1) a return to a more normal level of deferred income taxes and investment tax credits from a year earlier when additional tax payments related to the sale of facilities were made which reduced the net deferred income tax provisions in 1982, (2) the net non-cash charges against income in 1983 related to provisions for possible coal mine investment losses offset by amortization of the gain from the sale of generating facilities and (3) increased depreciation and amortization charges consistent with increased plant in service and amortizable canceled project investment.

Internally generated funds from depreciation and amortization will increase significantly when the Harris Unit No. 1 is placed into commercial operation in 1986, and to the extent that the investment in the canceled Harris Unit No. 2 is amortized (see Note 6 to Financial Statements).

The relative amounts of resources obtained from financing activities have been as follows:

	1983	1982	1981
Common and preferred stocks	33.9%	39.4%	30.3%
First mortgage bonds	71.4	87.1	5.5
Long-term notes		44.1	18.0
Commercial paper backed by long-term credit facility	(24.1)		29.2
Nuclear fuel financing arrangements	(4.4)	4.2	9.4
Short-term transactions	23.2	(74.8)	7.6
	100.0%	100.0%	100.0%
Total financings were (in millions):	$236.5	$136.7	$444.9

During 1983, the amount of financing activities continued at a reduced level, compared to 1981 and previous years, because of the $153.9 million available from 1982 Power Agency sale closings plus an additional $79.3 million in 1983. Issuances of common stock under the various plans increased in 1983 (See Note 3 to Financial Statements) primarily due to the increased interest in the dividend reinvestment program and an issuance of shares for employees under the ESOP program.

The cancellation of Harris Unit No. 2 has reduced significantly the capital requirements for 1985 and later years. Capital requirements for construction and nuclear fuel in 1984 and future years reflect significant reductions because of Power Agency's ownership interests. Increased inclusion by regulatory authorities of construction investment in the rate base reduces the amount of construction expenditures because less AFUDC is required to be capitalized (see Note 1(d) to Financial Statements).

The Company presently has on file with the Securities and Exchange Commission a shelf registration statement under which the Company can issue up to $150 million of additional First Mortgage Bonds (Shelf Bonds). The amount and timing of future sales of these and other securities will depend primarily upon market conditions and the needs of the Company.

The Company's ability to issue additional shares of preferred stock or First Mortgage Bonds is subject to earnings and other tests. Based upon unfunded property additions and retired bonds at December 31, 1983 and assuming the issuance of $150 million of Shelf Bonds, the Company could issue approximately $1.4 billion in additional First Mortgage Bonds. After the issuance of the Shelf Bonds (at an assumed rate of 13%) under the Company's Charter earnings test, at December 31, 1983, the Company could have issued approximately 3.6 million additional shares of preferred stock (at an assumed price of $100 per share and an $11.00 annual dividend rate). The 8 million authorized, but unissued, preference stock shares are not subject to an earnings test.

The Company currently expects to elect by June 30, 1985 to defer payments of the $88 million accrued liability for nuclear fuel disposal costs (see Note 8(e) to Financial Statements). The Company has the option until June of 1985 to pay the accrued amount at that time without interest, to elect to pay in quarterly installments with interest over a future ten-year period, or to pay in one lump sum with interest in the late 1990s.

Short-term liquidity: Customer receivables on the books at year-end represent an average of less than 20 days billings. At December 31, 1983, the Company had firm, unused bank lines of credit totaling $206.7 million and a $130 million irrevocable revolving credit facility supporting outstanding commercial paper of $73 million in addition to $57 million of pollution control First Mortgage Bonds that are redeemable annually at the option of the holder (annual tender bonds). In connection with those annual tender bonds, the Company has contracted for remarketing in the event of tender for repurchase. The obligations supported by the $130 million revolving credit facility are classified as long-term debt on the balance sheet. Proceeds from the issuance of the Series F pollution control bonds totaling $32.1 million are held in trust pending use for qualifying expenditures.

At December 31, 1983, the Company had unused investment tax credits of $109 million and a tax loss carryforward of approximately $81 million that can be used to reduce federal income tax payments in 1984, or later years if not used in 1984.

RESULTS OF OPERATIONS

Operating revenues increased during 1983 and 1982 principally because of: (1) general rate increases that produced $70.6 million more in 1983 as compared with 1982 and $140.5 million more in 1982 than in 1981, (2) fuel cost adjustment billings that decreased $21.0 million in 1983 from 1982 levels while increasing $34.3 million in 1982 over 1981 levels, and (3) a 1.3 percent overall increase in energy sales in 1983. The 1983 increases in energy sales includes the net effect of a 5.4 percent increase in retail and regular wholesale customer energy sales and a 36.1 percent decrease in Power Agency related sales, which fluctuate with output levels of the jointly-owned generating units as well as customer demands.

Operating expenses reflect increased costs of fuel due to greater generation of electricity in 1983 to serve increased customer needs and to replace a portion of the more expensive purchased and interchange power costs that occurred in the prior year. Generation from the coal-fired Mayo Unit No. 1 that was placed into commercial operation on March 1, 1983 was responsible for a substantial portion of the increased output. Also, nuclear fuel expense increased as the Company experienced increased nuclear power plant availability in 1983 as compared with 1982. The provision in 1983 for possible coal mine investment losses of $49.9 million increased operating expenses and is related to investment in coal mining subsidiaries (see Note 2 to Financial Statements).

Maintenance expense, which declined in 19[illegible] reflects a one-time credit of $15.7 million in order to capitalize certain replacements of property items at generating plants that were expensed in prior years, principally 1982 and also reflects on overall decrease at generating plants from levels in recent years. Generally, operating expenses increased, especially depreciation, due to Mayo Unit No. 1 being placed into commercial operation in early 1983.

Other Income declined due to a decrease in the allowance for other funds used during construction, reflecting reduced investments in construction, principally because the Mayo Unit No. 1 was placed into commercial operation. Other income also declined because of expenses of operation of the Company's coal mining subsidiaries. Income tax credits decreased principally because of lower capitalized interest charges. Offsetting these decreases in part is amortization of a portion of the gain from sale of generating facilities to the Power Agency.

Interest charges reflect lower short-term and variable long-term interest rates in 1982 and 1983. The allowance for borrowed funds used during construction, net of deferred income tax effects, decreased in 1983 because of reduced investments in construction. Furthermore, the inclusion of construction investments in the rate base decreased the allowance for borrowed and other funds by $39.5 million in 1983, $43.4 million in 1982 and $21.9 million in 1981. (See Note 1(d) to Financial Statements).

Net income and earnings: In summary, while earnings for 1983, 1982 and 1981 have increased from year to year, earnings have been adversely affected by continuing inflation, high levels of operation expenses and other cost increases not fully reflected in approved revenue levels. Interest rates and levels of inflation were lower in 1983 and had less adverse impact on earnings in 1983 than in recent years. The charge to operations for possible investment losses applicable to the coal mine subsidiaries adversely affected 1983 results. Increased energy sales because of colder weather and an upturn in economic activity contributed favorably to earnings in 1983. The quality of earnings has improved somewhat because of less AFUDC and more compensating revenue, as increased amounts of construction investment have been allowed in the rate base. Earnings per share of common stock have been adversely affected by the increased number of shares outstanding.

IMPACTS OF INFLATION

See Supplemental Inflation Adjusted Data in ITEM 8 for the estimated effects of changing prices on income on the basis prescribed by the Financial Accounting Standards Board.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following financial statements, supplementary data and financial statement schedules are included herein:

All other schedules are omitted as they are either not required, not applicable, or the information is otherwise provided.

Deloitte Haskins+Sells

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Post Office Box 2778
Raleigh, North Carolina 27602
(919) 828-0716
Cable DEHANDS

Auditors' Opinion

Carolina Power & Light Company:

We have examined the financial statements and supplemental financial statement schedules of Carolina Power & Light Company listed in the accompanying table of contents. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 6, the Company has canceled plans for construction of a nuclear generating unit and intends to request permission in each of its regulatory jurisdictions to recover its costs related to such unit. The final outcome of this matter cannot presently be determined.

In our opinion, subject to the effects on the financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty referred to in the preceding paragraph been known, the financial statements referred to above present fairly the financial position of the Company at December 31, 1983 and 1982 and the results of its operations and the source and use of its financial resources for each of the three years in the period ended December 31, 1983, in conformity with generally accepted accounting principles applied on a consistent basis. Also, in our opinion, subject to the qualification referred to above, such supplemental financial statement schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

We have also previously examined, in accordance with generally accepted auditing standards, the balance sheets and schedules of capitalization as of December 31, 1981, 1980 and 1979, and the related statements of income, retained earnings and source and use of financial resources for the years ended December 31, 1980 and 1981 (none of which are presented herein); and we expressed unqualified opinions on those financial statements; however, if we were to reissue our opinion on these statements currently, it would be qualified similarly to the preceding paragraph. In our opinion, subject to the qualification referred to above, the selected financial data for each of the five years in the period ended December 31, 1983, appearing on Page 30, is fairly presented in all material respects in relation to the financial statements from which it has been derived.

DELOITTE HASKINS & SELLS
February 15, 1984

Balance Sheets

Carolina Power & Light Company December 31, 1983 and 1982

Assets	1983	1982
	(In Thousands)	
Electric Utility Plant:		
Electric utility plant other than nuclear fuel:		
In service	$3,629,625	$3,019,141
Held for future use	12,902	10,350
Construction work in progress	1,697,551	1,994,906
Total	5,340,078	5,024,397
Less accumulated depreciation	884,250	792,013
Net	4,455,828	4,232,384
Nuclear fuel	264,802	231,518
Less accumulated amortization	149,424	131,280
Net	115,378	100,238
Electric utility plant, net	4,571,206	4,332,622
Current Assets:		
Cash and temporary cash investments	9,214	8,028
Accounts receivable, net	97,651	75,140
Power Agency Trust Fund		153,891
Materials and supplies:		
Fuel	101,893	121,896
Other	25,338	29,495
Deferred fuel cost	6,186	5,070
Current portion of deferred income taxes	16,967	16,948
Prepayments, etc.	9,162	20,636
Total current assets	266,411	431,104
Other Assets:		
Unamortized canceled project costs:		
Harris Unit No. 2 (Note 6)	263,733	
Harris Units Nos. 3 and 4 (Note 8(f))	121,460	124,587
Unrecovered nuclear fuel disposal costs (Note 8(e))	29,267	
Investment in coal-mining subsidiaries (Note 2)	2	19,620
Miscellaneous other property and investments	22,348	18,560
Unamortized debt expense	3,467	3,230
Other deferred debits	15,712	21,232
Total other assets	455,989	187,229
Total	$5,293,606	$4,950,955

See notes to financial statements.

Balance Sheets

Carolina Power & Light Company December 31, 1983 and 1982

Liabilities	1983	1982
	(In Thousands)	
Capitalization (see Schedules of Capitalization):		
Common stock	$1,151,323	$1,071,863
Common stock subscribed	2,205	1,528
Retained earnings	432,913	388,774
Preference stock	47,900	47,900
Preferred stock—redemption not required	238,118	238,118
Preferred stock—redemption required, net	214,785	214,743
Long-term debt (excluding current maturities), net	1,909,823	1,891,702
Total capitalization (excluding current maturities of long-term debt)	3,997,067	3,854,628
Current Liabilities:		
Long-term debt due within one year	21,849	64,122
Notes payable:		
Bank demand notes		13,000
Other (principally commercial paper)	82,703	19,210
Accounts payable:		
Construction contract retentions	5,370	13,725
Other	126,055	109,839
Customers' deposits	7,905	7,025
Taxes accrued	41,782	68,467
Interest accrued	42,378	41,491
Dividends declared	58,833	54,769
Other	4,319	4,005
Total current liabilities	391,194	395,653
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes:		
Harris Units Nos. 2, 3 and 4	134,702	35,885
Gain on sale of facilities (Note 7)	(98,125)	(94,080)
Other, net	494,624	447,926
Total accumulated deferred income taxes	531,201	389,731
Accumulated deferred investment tax credits	174,112	180,700
Unamortized gain on sale of facilities (Note 7)	128,104	117,348
Other	71,928	12,895
Total deferred credits and other liabilities	905,345	700,674
Commitments and Contingencies (Notes 2, 6, 7 and 8)		
Total	$5,293,606	$4,950,955

See notes to financial statements

Statements of Income

Carolina Power & Light Company For the Years Ended December 31,

	1983	1982	1981
	(In Thousands Except Earnings Per Share)		
Operating Revenues (Note 9)	$1,647,183	$1,538,165	$1,343,558
Operating Expenses:			
Operation:			
Fuel for generation	517,625	473,509	459,591
Deferred fuel costs	(1,115)	1,423	523
Purchased and interchange power, net	18,583	50,226	19,388
Other (Note 2)	285,671	233,147	174,084
Maintenance	137,383	167,458	125,876
Depreciation and amortization (Note 1)	148,342	126,355	110,409
Taxes other than on income	114,295	104,300	97,288
Income tax expense (Note 5)	162,443	133,622	118,996
Total operating expenses	1,383,227	1,290,040	1,106,155
Operating Income	263,956	248,125	237,403
Other Income:			
Allowance for other funds used during construction	94,927	98,353	92,508
Income tax credits (Note 5)	31,078	38,472	35,846
Amortized gain on sale of facilities (Note 7)	11,422		
Other income (deductions), net (Note 2)	(4,945)	13,919	8,593
Total other income	132,482	150,744	136,947
Income Before Interest Charges	396,438	398,869	374,350
Interest Charges:			
Long-term debt	171,448	180,986	177,981
Other	17,551	34,001	31,201
Allowance for borrowed funds used during construction-credit (Note 5)	(31,830)	(43,265)	(38,429)
Net interest charges	157,169	171,722	170,753
Net Income	239,269	227,147	203,597
Preferred and Preference Stock Dividend Requirements	44,605	44,605	42,660
Earnings for Common Stock	$ 194,664	$ 182,542	$ 160,937
Average Common Shares Outstanding	60,645	57,539	52,554
Earnings Per Common Share	$ 3.21	$ 3.17	$ 3.06

See notes to financial statements.

Statements of Retained Earnings

For the Years Ended December 31,

	1983	1982	1981
	(In Thousands)		
Balance at Beginning of Year	$ 388,774	$ 345,353	$ 309,819
Net Income	239,269	227,147	203,597
Total	628,043	572,500	513,416
Deduct:			
Cash dividends declared:			
Preferred and Preference Stock at stated rates (Note 1)	44,605	44,605	44,060
Common Stock (at annual rate of $2.46 a share in 1983, $2.40 in 1982 and $2.32 in 1981)	150,423	138,878	123,578
Total cash dividends declared	195,028	183,483	167,638
Capital stock discount and expense	102	243	425
Total deductions	195,130	183,726	168,063
Balance at End of Year	$ 432,913	$ 388,774	$ 345,353

See notes to financial statements.

Statements of Source and Use of Financial Resources

Carolina Power & Light Company For the Years Ended December 31.

	1983	1982	1981
		(In Thousands)	
Source of Financial Resources:			
Current resources provided from operations:			
Net income	$ 239,269	$ 227,147	$ 203,597
Items not requiring (providing) current resources:			
Depreciation and amortization	180,565	141,334	150,105
Amortized gain on sale of facilities	(11,422)		
Provision for possible coal-mine investment losses	49,868		
Noncurrent deferred income taxes, net	172,341	10,391	150,940
Investment tax credit adjustments, net	(6,589)	88,493	(28,569)
Other funds portion of AFUDC	(94,927)	(98,353)	(92,508)
Total current resources provided from operations	529,105	369,012	383,565
Sale of generating facilities	79,301	584,801	
Total current resources	608,406	953,813	383,565
Additions to plant accounts representing capitalization of other portion, less deferred income taxes on borrowed funds portion of AFUDC	64,056	56,405	55,231
Total resources provided excluding financings	672,462	1,010,218	438,796
Financings:			
First mortgage bonds	168,767	119,038	24,248
Preferred stock			39,458
Common stock—Public offerings			59,616
Common stock—Plans (Note 3)	80,077	53,852	35,931
Other long-term notes	42	60,270	80,000
Commercial paper backed by long-term credit facility	(57,015)		130,000
Nuclear fuel trust and lease obligations	(10,409)	5,731	41,954
Decrease in temporary cash investments plus increase in short-term notes payable	54,993	(102,195)	33,705
Total resources provided from financings	236,455	136,696	444,912
Total	$ 908,917	$1,146,914	$ 883,708
Use of Financial Resources:			
Gross property additions, excluding nuclear fuel*	$ 660,130	$ 638,284	$ 548,508
Nuclear fuel additions*	48,488	16,450	36,223
Canceled projects expenditures	20,710	15,355	
Dividends for the year	195,028	183,483	166,238
Repayment of first mortgage bonds	123,346	20,000	15,000
Repayment of other long-term debt	2,333	140,064	
Repayment of nuclear fuel lease obligation			45,827
Net increase (decrease) in the following working capital components:			
Power Agency trust fund	(153,891)	153,891	
Accounts receivable, net	22,511	4,284	8,019
Materials and supplies	(24,160)	13,968	19,930
Accounts payable	(7,861)	(10,482)	56,943
Reserve for refund of revenues	499	24,094	(16,799)
Other, net	15,389	(25,687)	(11,002)
Miscellaneous, net	6,395	(26,790)	14,821
Total	$ 908,917	$1,146,914	$ 883,708

*Includes amounts capitalized as allowance for funds used during construction, net of related deferred income taxes.

See notes to financial statements.

Schedules of Capitalization
Carolina Power & Light Company December 31, 1983 and 1982

			1983	1982
			(In Thousands)	
COMMON STOCK EQUITY (Note 3):				
Common stock without par value, authorized, 100,000,000 shares: Outstanding 62,484,959 shares at December 31, 1983 and 58,835,176 shares at December 31, 1982			$1,151,323	$1,071,863
Subscribed			2,205	1,528
Retained earnings, limited in payment as dividends under certain circumstances under the Company's charter; however, none restricted at December 31, 1983			432,913	388,774
Total common stock equity			$1,586,441	$1,462,165
PREFERENCE AND PREFERRED STOCK, without par value, cumulative (Note 3):	At December 31, 1983			
	Redemption Price	Shares Outstanding		
Preference stock, authorized 10,000,000 shares (entitled to $25 a share plus accumulated dividends in the event of liquidation, in preference only to common stock)—				
$2.675 Series A	$ 26.50	2,000,000	$ 47,900	$ 47,900
Preferred stock (a)—redemption not required:				
$5 Preferred Stock—authorized, 300,000 shares	$110.00	237,259	$ 24,376	$ 24,376
Serial Preferred Stock(b):				
$4.20 Series	102.00	100,000	10,000	10,000
5.44 Series	101.00	250,000	25,000	25,000
9.10 Series	103.00	300,000	30,000	30,000
7.95 Series	104.00	350,000	35,000	35,000
7.72 Series	104.00	500,000	49,425	49,425
8.48 Series	105.00	650,000	64,317	64,317
Total—redemption not required		2,387,259	$ 238,118	$ 238,118
Preferred stock (a)—redemption required (c):				
Serial Preferred Stock (b)—				
$11.16 Series	$111.16	400,000	$ 40,000	$ 40,000
14.00 Series	114.00	400,000	40,000	40,000
Preferred Stock A, authorized, 5,000,000 shares:				
$7.45 Series	104.00	500,000	50,000	50,000
8.75 Series	107.23	500,000	50,000	50,000
9.25 Series	104.50	180,000	18,000	18,000
9.00 Series	(c)	175,000	17,500	17,500
Unamortized discount			(715)	(757)
Total—redemption required		2,155,000	$ 214,785	$ 214,743

(a) Entitled to $100 a share plus accumulated dividends in the event of liquidation.
(b) Authorized, 20,000,000 shares in total.
(c) Minimum sinking fund requirements (at $100 per share plus accumulated dividends) commence in 1984 for the $7.45 Series, at 20,000 shares per year; in 1985 for the $8.75 Series at 20,000 shares per year and increasing in the year 2000 to 40,000 shares annually; in 1986 for the $11.16 Series at 12,000 shares per year; in 1987 for the $14.00 Series at 16,000 shares per year; and in 1990, for the $9.00 Series, all 175,000 shares are to be redeemed. With respect to the $9.25 Series, the Company must offer to redeem annually, on March 1 of each year beginning in 1988, any or all shares outstanding. Minimum sinking fund requirements for the next five years aggregate: 1984, $2,000,000; 1985, $4,000,000; 1986, $5,200,000; 1987, $6,800,000 and 1988, $6,800,000.

See notes to financial statements

	1983	1982
	(In Thousands)	
LONG-TERM DEBT (a):		
First mortgage bonds-principal amounts:		
Other than Pollution Control Series:		
Maturing 1983 through 1993:		
11 % due April 15, 1984 (redeemed 10-15-83)		$ 67,346
14⅛% due April 1, 1987	$ 125,000	125,000
4⅛% due March 1, 1988	20,000	20,000
4⅞% due April 1, 1990	25,000	25,000
4½% due November 1, 1991	25,000	25,000
11⅜% due December 1, 1992	100,000	100,000
Maturing 1994 through 1998—4½% to 6⅞%	140,000	140,000
Maturing 1999 through 2003—7⅛ to 8¾%	525,000	525,000
Maturing 2004 through 2008—8½% to 9¼%	325,000	325,000
Maturing 2009 through 2013—10½% to 12⅞%	325,000	225,000
Pollution Control Series:		
A. 8 % due 2001-2009 (principal amount less proceeds held by Trustee: 1982, $1,900)	63,000	61,100
B. 7¼% due 10-1-83 (principal amount less proceeds held by Trustee: 1982, $12,227)		37,773
C. 7¼% due 10-1-83		6,000
D. (5.65% to 4/1/84) due 4-1-2009	48,485(b)	
E. (5.65% to 4/1/84) due 4-1-2009	5,970(b)	
F. (7.00% to 11/1/84) due 11-1-2010 (principal amount less proceeds held by Trustee: 1983, $32,140)	2,560(b)	
Total first mortage bonds-principal amounts	1,730,015	1,682,219
Other long-term debt:		
Nuclear fuel trust obligations (variable rates: 10.47% average effective interest cost at 12-31-83; 9.56% at 12-31-82)	80,215	90,624
16½% Guaranteed Notes (Finance N.V.) due 2-15-89 (Note 1 [b])	60,000	60,000
Carolina Pipeline (Variable interest rate - 11.5% at 12-31-82)		2,333
Commercial paper backed by long-term credit facility to 9-24-86 (9.70% average effective interest rate at 12-31-83; 8.66% at 12-31-82)	72,985	130,000
Miscellaneous promissory notes	107	66
Total long-term debt, principal amounts	1,943,322	1,965,242
Unamortized discount and premium, net	(11,650)	(9,418)
Total long-term debt, including current maturities	1,931,672	1,955,824
Less long-term debt due within one year:		
Nuclear fuel trust obligations	21,849	19,882
7¼% Pollution Control Bonds, due 10-1-83		43,773
Carolina Pipeline due 10-1-83		467
Total long-term debt, excluding current maturities	$1,909,823	$1,891,702
TOTAL CAPITALIZATION (excluding current maturities of long-term debt)	$3,997,067	$3,854,628

(a) Long-term debt maturities for the next five years, including estimated amounts under continuous nuclear fuel financing arrangements for which repayments of present obligations are based on energy produced, are (in thousands):

	1984	1985	1986	1987	1988
First mortgage bonds				$125,000	$20,000
Nuclear fuel	$21,849	$18,488	$ 20,877	10,507	3,556
Long-term credit facility obligations			130,000		
Totals	$21,849	$18,488	$150,877	$135,507	$23,556

(b) Redeemable annually at the option of the holder—backed up by a portion of the long-term credit facility of $130,000,000.

See notes to financial statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

(a) System of Accounts. The accounting records of the Company are maintained as prescribed in uniform systems of accounts of the Federal Energy Regulatory Commission (FERC) and the regulatory commissions of North Carolina and South Carolina.

(b) Subsidiaries. The Company's financial statements reflect consolidation of its wholly-owned foreign financing subsidiary, Carolina Power & Light Finance N.V., which in 1982 was organized and issued $60,000,000 principal amount of 16½% Guaranteed Notes. See Note 2 for information on the coal-mining subsidiaries.

(c) Electric Utility Plant. The cost of additions, including replacements of units of property and betterments, is charged to utility plant. Maintenance and repairs of property, and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense. The cost of units of property replaced or renewed or otherwise retired, plus removal or disposal costs, less salvage, is charged to accumulated depreciation. Electric utility plant, other than nuclear fuel, is subject to the lien of the Company's mortgage. Nuclear fuel is pledged, or subject to be pledged, as collateral for nuclear fuel financing arrangements.

(d) Allowance for Funds Used During Construction (AFUDC). As prescribed in regulatory uniform systems of accounts, an allowance for the cost of borrowed and other funds used to finance electric utility plant construction, less applicable income taxes, is charged to cost of plant. Regulatory authorities consider the inclusion of these recognized costs as appropriate for the purpose of establishing rates for the Company's utility charges to customers over the service lives of the property. The other portion of AFUDC is credited to other income, the borrowed funds portion is credited to interest charges and the deferred income tax provision is reflected as a reduction in AFUDC-borrowed funds. The composite, net-of-tax AFUDC rate was approximately 9.3 percent in 1983 and 1982 and 8.8 percent in 1981.

Certain construction-work-in-progress expenditures (totaling $662,570,000, $412,535,000, $405,419,000 and $229,590,000 at December 31, 1983, 1982, 1981 and 1980, respectively) are included in the rate base for ratemaking purposes. AFUDC is not capitalized (charged to the cost of plant) on such expenditures.

(e) Depreciation and Amortization. Depreciation of utility plant, other than nuclear fuel, for financial reporting purposes is computed on the straight-line method based on estimated remaining useful lives, adjusted for estimated net salvage or disposal costs, and charged principally to depreciation expense. Depreciation provisions, as a percent of average depreciable property other than nuclear fuel, approximated 3.8 percent in 1983 and 1982 and 3.6 percent in 1981. Depreciation rates are reviewed periodically and changes in estimates (including the costs to dismantle or decontaminate nuclear generating plants) are made, as appropriate, on a prospective basis.

Allowable depreciation rates for wholesale ratemaking purposes have been different from those regularly used by the Company and allowed by other ratemaking jurisdictions; therefore, the Company recorded lower depreciation provisions solely applicable to wholesale operations ($1,947,000 less for 1983, $1,527,000 less for 1982 and $3,383,000 less for 1981).

Amortization of nuclear fuel costs (1983, $30,594,000; 1982, $13,536,000; 1981, $38,784,000), including disposal costs through April 6, 1983, is computed on the unit of production method and charged to fuel expense. The amortization charges for disposal costs totaled, for 1983 through April 6, $3,650,000, for 1982, $7,684,000 less a wholesale revenue refund related reduction of $14,313,000 applicable to the years 1977-1982, and for 1981, $10,064,000. Nuclear fuel disposal costs are paid quarterly for nuclear generation after April 6, 1983. (See Note 8(e)).

(f) Revenues. Customers' meters are read and bills are rendered on a cycle basis. Revenues are recorded when billed, as is the customary practice in the industry.

(g) Deferred Fuel Costs. The Company's rates in all three of its regulatory jurisdictions are adjustable for fluctuations in fuel costs. For South Carolina retail operations the Company defers the difference between fuel costs incurred and the related customer billings and periodically adjusts rates to reflect this difference. For wholesale operations, the Company adopted a similar procedure effective January 1982. For North Carolina retail operations, pursuant to a June 1982 amendment to North Carolina utilities law, the fuel cost component of rates reflects estimated fuel expense for the period that the rates will be in effect and may be adjusted once in every twelve months in fuel-cost-only proceedings. In addition, fuel costs may be considered in general rate case proceedings.

Effective for service rendered on and after September 19, 1983 the North Carolina Utilities Commission approved a general rate increase that included a base fuel component of $.01677 per KWH (up from $.01611) and directed the establishment of an interim deferred account for variations between actual fuel expense incurred and the base fuel component revenues, providing consideration of the deferred amounts in the next general rate case hearing now planned for the third quarter of 1984. At December 31, 1983 the Company has deferred $1,627,000 of costs incurred in excess of such base fuel component revenues.

(h) Income Taxes. Comprehensive interperiod income tax allocation has been observed, beginning in 1976, for all significant timing differences. In compliance with regulatory accounting, income taxes are allocated between operating income and other income, principally with respect to interest charges related to construction work in progress. The Company and its domestic subsidiaries file consolidated federal income tax returns. Income taxes are allocated among the companies based upon the ratios of their respective "separate tax liabilities" to the consolidated tax liability. See Note 5 with respect to certain other income tax information.

(i) Investment Tax Credits. Investment tax credits are being amortized over the service lives of the property.

(j) **Preferred and Preference Dividends.** Preferred and preference dividends declared and charged to retained earnings include amounts applicable to the first quarter of the following year, except for the Preferred Stock A series which dividends are wholly applicable to the year in which declared.

(k) **Retirement Plan.** The Company has a noncontributory retirement plan for all full-time employees and is funding the costs accrued under the plan. Retirement plan costs for 1983, 1982 and 1981 were approximately $14,256,000, $15,946,000 and $11,223,000, respectively. The actuarial present value of accrued benefits (assuming rates of return of 11 percent and 14 percent, respectively) and the market value of assets available for benefits, as of the most recent valuation dates, are as follows (in thousands):

	January 1, 1983	January 1, 1982
Actuarial present value of accrued plan benefits		
Vested	$ 52,094	$35,643
Nonvested	7,309	4,391
Total	$ 59,403	$40,034
Market value of assets available for benefits	$103,640	$69,995

(l) **Other Policies.** Other property and investments are stated principally at cost, less accumulated depreciation where applicable. Materials and supplies inventories are stated at average cost. The Company maintains an allowance for doubtful accounts receivable (1983, $2,477,000; 1982, $1,757,000). Bond premium, discount and expense are amortized over the life of the related debt.

2. Investment in Coal-Mining Subsidiaries

On November 29, 1983, the Company acquired the remaining 20 percent interests in its two coal-mining subsidiaries, Leslie Coal Mining Company (Leslie) and McInnes Coal Mining Company (McInnes).

At December 31, 1983, Leslie's and McInnes' total assets were approximately $131 million. The Company has guaranteed their obligations of approximately $108.5 million.

The Company purchased coal from the subsidiaries for $21,843,000, $48,178,000 and $37,314,000 during 1983, 1982 and 1981, respectively, representing the costs of production for the mines. During 1982, the Company wrote off the accumulated excess of costs of production over fair market value of its coal purchases that had been previously deferred. In 1983 the Company charged $49,868,000 to other operation expense for possible losses on its investments in the mines. The subsidiaries suspended production in the first quarter of 1983 and the Company has since then recorded in other income the carrying charges and other expenses of approximately $1,300,000 per month. The Company currently plans to sell the properties. Pickands Mather & Company, the previous minority owner, continues to manage and operate the mines.

3. Capital Stock Issued and Reserved

Capital stock shares have been issued as follows, representing the total changes in the respective accounts in the years indicated (in thousands):

	1983	1982	1981
Common stock:			
Public offerings			3,000
SPSP	812	669	590
ADRP	2,034	1,722	1,257
ESOP	494	73	70
CSOP	310	232	14
Total	3,650	2,696	4,931
Preferred Stock—redemption required:			
Serial preferred stock $14.00 Series			400

At December 31, 1983, 1,425,211 shares of common stock were reserved for issuance under the Stock Purchase-Savings Program for Employees (SPSP), 6,134,960 shares under the Automatic Dividend Reinvestment Plan (ADRP), 1,080,406 shares under the Employee Stock Ownership Plan (ESOP) and 1,444,432 shares under the Customer Stock Ownership Plan (CSOP).

4. Notes Payable and Lines of Credit

At December 31, 1983, the Company had firm, unused lines of credit with various financial institutions totaling $206,690,000 including necessary amounts to back up the outstanding current liability portion of commercial paper; and, in connection with these lines of credit, is required to maintain average compensating balances in various banks of $952,500 and pay commitment fees of approximately $61,000 per month. Such lines of credit are reviewed periodically, at which time they may be renewed or canceled.

5. Income Taxes

The provisions for income tax expense are composed of the following (in thousands):

	Year Ended December 31, 1983	1982	1981
Included in operating expenses:			
Currently payable taxes—Federal	$ 7,316	$ 29,055	$ 52,732
—State	(106)	18,933	(427)
Deferred taxes, net—Federal	142,887	913	80,854
—State	19,137	(1,939)	14,237
Investment tax credit adjustments, net	(6,791)	86,660	(28,400)
Total	162,443	133,622	118,996
Included in other income (a):			
Reduction in currently payable taxes—Federal	(9,791)	(1,088)	(58,026)
—State	(813)	(1,524)	(1,037)
Deferred taxes—Federal (a)	(18,238)	(35,514)	26,720
—State (a)	(2,337)	(2,179)	(3,334)
Investment tax credit adjustments, net	101	1,833	(169)
Total	(31,078)	(38,472)	(35,846)
Total income tax expense	$131,365(a)	$ 95,150(a)	$ 83,150[illegible]

(a) Deferred income tax provisions totaling $30,871,000 for 1983, $41,948,000 for 1982 and $37,277,000 for 1981 related to the tax effects of the allowance for borrowed funds charged to the cost of plant are reflected in the statements of income as a reduction in the Allowance for Borrowed Funds Used During Construction - Credit.

Provisions for net deferred income taxes related to the following (in thousands):

	1983	1982	1981
Differences between book depreciation and amortization and tax deductions for property costs:			
Pre-operational tax deductions (taxes and other costs capitalized, etc.)-originating differences	$ 11,091(b)	$ 11,863(b)	$ 8,515[illegible])
Nuclear fuel disposal costs	41,874	(19,466)	526
Accelerated depreciation and other property cost differences:			
Originations	62,374	59,131	43,109[illegible])
Reversals	(32,990)	(37,753)	
Deferred recognition of gain on sale of generating facilities, net	(4,201)	(94,080)	
Unbilled revenues, net	1,770	(19,729)	
Deferred tax gain on sale of facilities, net	16,660	62,160	
Provision for possible refund of revenues, net	(17)	11,546	5,902
Utilization of subsidiaries' tax losses	8,347	5,871	6,439
Canceled project costs, net	93,432	(14,100)	49,373
Tax loss carryforward	(39,650)		
Miscellaneous other timing differences, net	(17,232)	(4,162)	4,613
Total provisions for deferred income taxes, net	$141,449	$(38,719)	$118,477

(b) Excludes deferred tax provisions relating to tax effects of borrowed funds capitalized (see (a) above).

(c) Reclassification of detail for originations and reversals for 1981 is not practical.

A reconciliation of the Company's effective income tax rate (computed by dividing total income tax expense, including amounts reflected as a reduction in AFUDC on borrowed funds, by pretax income) to the statutory federal income tax rate follows:

	Year Ended December 31,		
	1983	1982	1981
Effective income tax rate	40.4%	37.6%	37.2%
The effects of including AFUDC on other funds in pretax income	12.5	14.0	14.8
Effective income tax rate, excluding AFUDC on other funds from pretax income	52.9	51.6	52.0
State income taxes, net of federal income tax benefit	(3.4)	(3.8)	(3.3)
Other differences, net	(3.5)	(1.8)	(2.7)
Statutory federal income tax rate	46.0%	46.0%	46.0%

At December 31, 1983, the Company had generated but not utilized investment tax credits totaling approximately $109 million (including $10 million of ESOP credits). The Company also generated a tax loss carryforward estimated at $81 million in 1983 and expected to be utilized in 1984.

6. Harris Unit No. 2

In December 1983, the Company canceled further construction on Harris Unit No. 2, a 900,000 kilowatt nuclear generating unit planned for completion in 1990. The Company's share of the estimated final investment in the jointly owned canceled unit is $315 million. The Company is seeking regulatory permission to write off the costs over a period of ten years and to recover such costs through rates.

7. Joint-Ownership of Generating Facilities

The North Carolina Eastern Municipal Power Agency (Power Agency), which members include a majority of the Company's previous municipal wholesale customers, has acquired undivided ownership interests in certain generating facilities of the Company. The Company and Power Agency are entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share, on a current basis, of additional construction costs, fuel inventory purchases and operating expenses for each unit. Power Agency's payment obligation with respect to cancellation costs for Harris Units Nos. 2, 3 and 4 is 12.94 percent of such costs.

At December 31, 1983, the Company's ownership interests and investments in the jointly owned generating facilities were as follows (dollars in millions):

Plant or Unit (Type Fuel)	Megawatt Capability	Ownership Interest	Company Investment* Plant in Service	Company Investment* Under Construction
Mayo Plant (Coal)	1,440**	83.83%	$420.5	$ 13.2
Harris Plant (Nuclear)	900**	83.83%		1,438.7
Brunswick Plant (Nuclear)	1,580	81.67%	729.6	100.9
Roxboro Unit No. 4 (Coal)	700	87.06%	186.7	1

*Does not include nuclear fuel costs.
**Design target capability.

The Company does not maintain its accumulated depreciation accounts on a separate unit basis and, therefore, amounts applicable to the Mayo Plant, Brunswick Plant and Roxboro Unit No. 4 are not shown above. The Company's share of expenses for the jointly owned units is included in the appropriate expense category in the statements of income.

The total gain from the sale of the generating facilities to the Power Agency was $32.3 million net of income taxes and is being amortized to other income over three years beginning October 1, 1983.

In connection with the sale of these facilities, the Company is obligated to purchase portions (generally starting at 50 percent) of the Power Agency's ownership capacity and energy for the Mayo and Harris units, commencing with commercial operation of each unit and declining ratably during the following fifteen-year period. The minimum payments applicable to Mayo Unit No. 1 and Harris Unit No. 1 are presently estimated at $5,561,000, $5,168,000, $35,285,000, $38,588,000, and $35,786,000, for the years 1984 through 1988, respectively, and $210,195,000 for the period 1989 through 2000, representing total estimated future minimum payments of $330,583,000 for such capacity. Variable costs of such purchases are primarily fuel costs, maintenance and other operation expenses for the respective units. Contractual purchases from Mayo Unit No. 1 commenced on its commercial operation date, March 1, 1983, and totaled $14,800,000 for 1983.

8. Commitments and Contingencies

(a) Construction and Nuclear Fuel. The Company has incurred substantial commitments in connection with its construction program. Construction expenditures are estimated to be $1.7 billion and nuclear fuel expenditures $278 million for 1984 through 1986 in connection with that program.

(b) Leases. Rental commitments for operating leases and for unrecorded capital leases at December 31, 1983 are not material with respect to the Company's financial position or results of operations.

(c) Insurance. The Company is a member of Nuclear Mutual Limited (NML), established to provide insurance coverage against property damage to insured's nuclear generating facilities. The Company is insured thereunder for $500 million at the Brunswick Plant and $500 million at the Robinson Plant. The Company currently would be subject to maximum retrospective premium assessments of approximately $65 million in the event losses at insured facilities exceed premiums, reserves, reinsurance and other NML resources, which are at present more than $300 million.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL), initially established to provide insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages of members' nuclear generating units. The Company is insured thereunder for $2,500,000 per week for 12 months (starting 26 weeks after the outage) and for $1,250,000 per week for the next 12 months for each operating nuclear generating unit. NEIL also provides decontamination and excess property insurance for nuclear generating facilities. The Company is insured thereunder for $435 million excess of $500 million at both its Brunswick and Robinson plants. The Company currently would be subject to retrospective premium assessments of up to approximately $23 million with respect to the incremental replacement power costs coverage and $15 million with respect to the decontamination and excess property coverage in the event covered expenses at insured facilities exceed premium reserves, reinsurance and other NEIL resources.

The Company's public liability for a nuclear incident is protected up to the maximum limit on public liability claims pursuant to the Price-Anderson Act, which is $580 million for each occurrence, through conventional insurance pools and through an industry retrospective assessment program. In the event that public liability claims from an insured nuclear incident exceed the primary financial protection provided by the insurance pools, which is currently $160 million, the Company would be subject to a pro rata assessment of up to a maximum of $15 million with respect to any single nuclear incident and an aggregate maximum of $30 million within any calendar year.

(d) Claims. There are certain claims pending against the Company. In the opinion of the Company, liabilities, if any, arising from these claims would not have a material effect on the financial position or results of operations of the Company.

(e) Nuclear Fuel Disposal Cost. The Nuclear Waste Policy Act of 1982 establishes that the federal government is responsible for the disposal of spent nuclear fuel and that the owners and operators of nuclear generating facilities will make payments to cover those costs. At December 31, 1983, the net remaining accumulated provisions for the estimated costs of such disposal costs incurred through April 6, 1983 are $29,267,000 less than the required payments of $88 million. Amounts attributable to wholesale customers totaling approximately $10 million, previously required to be refunded, may be recovered in proceedings before the FERC. The Company expects to prospectively increase its charges to operations for fuel expense over a reasonable period of time for this change in the estimated costs for spent fuel disposal. The Company must select by June 30, 1985 from one of several payment options for the costs incurred through April 6, 1983. Costs incurred thereafter are paid quarterly.

(f) Harris Units Nos. 3 and 4. In December 1981, the Company eliminated these units from its construction program. Pursuant to regulatory authorizations, the Company began amortizing in July 1982 the costs associated with these units and is recovering the costs through revenues. Amounts amortized to operating expenses totaled $13,251,000 in 1983 and $6,955,000 in 1982.

9. Other Rate Matters

Operating revenues increased $70,616,000 in 1983 over 1982 and $140,548,000 in 1982 over 1981, attributable to general rate increases placed into effect since 1980. Also included in revenues, representing fuel cost billings above a base cost of fuel (as defined for each ratemaking jurisdiction), is $40,617,000 for 1983, $61,645,000 for 1982 and $27,327,000 for 1981.

Summary of Quarterly Financial Data

(Composite Transactions-Reported Prices
Traded on the New York and Pacific Stock Exchanges)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Amount in thousands except for per share data)			
1982				
Operating Revenues	$405,559	$359,935	$402,342	$370,329
Operating Income	90,134	44,750	57,768	55,473
Net Income	81,455	37,722	55,232	52,738
Earnings Per Common Share	1.24	46	76	71
Dividend Paid Per Common Share	60	60	60	60
Common Stock Price Per Share:				
High	23	22¼	22¼	21⅞
Low	19½	19⅜	19	18⅞
1983				
Operating Revenues	$416,638	$361,370	$448,720	$420,455
Operating Income	81,359	49,853	69,540	63,204
Net Income	78,460	44,438	60,182	56,189
Earnings Per Common Share	1.13	55	80	72
Dividend Paid Per Common Share	60	60	60	63
Common Stock Price Per Share:				
High	23	22¾	23¼	25⅛
Low	20⅜	[illegible]	20½	21½

Supplemental Inflation Adjusted Data (Unaudited)

The data, as reported in the primary financial statements, are based on actual, nominal, historical costs. However, during periods of significant changes in general price levels, that nominal dollar information becomes distorted and fails to reflect real economic costs or value. The conventional basis does not account for the event of inflation, i.e., variations over time in the purchasing power or value of the dollar. In an effort to provide financial information about the effects of changing price levels, the Financial Accounting Standards Board issued Statement No. 33, Financial Reporting and Changing Prices, in September 1979. This statement requires most larger companies to disclose (among other things) certain significant historical cost data in constant dollars represented by the average level during the year of the Consumer Price Index for all Urban Consumers (CPI-U) and current cost information concerning the measurement of assets and the expiration of asset values.

The **constant dollar** information on the following pages reflects the nominal historical costs and prices restated by applying the CPI-U in conformity with Statement No. 33.

The **current cost** information on the following pages reflects changes in specific prices of plant from the date the plant was acquired to the present and differs from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general. The current cost of property, plant and equipment, which includes land, land rights, intangible plant, property held for future use and construction-work-in progress, represents the estimated cost of replacing existing plant assets and was determined primarily by indexing the surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. The current cost of nuclear fuel was determined by recent invoice prices. The current year's provision for depreciation and amortization was determined by applying the Company's depreciation and amortization rates to the indexed current cost amounts.

Under ratemaking practices established by regulatory commissions, the Company can recover through revenues only the original cost (historical cost/nominal dollars) depreciation. Therefore, the increase in the dollar amount for the cost of plant (stated in either historical cost/constant dollars or current cost) over the original cost is deemed not presently recoverable and, therefore, must be reflected as a "reduction in assets to net recoverable cost."

To further reflect the economics of regulation, the reduction in asset "cost" is offset to the extent that the plant is financed from sources that have a fixed, or contractural, rate of return and claim against assets of the Company. Under present ratemaking practices, the Company can recover through revenues the contractual rate of return for such capital and, therefore, is able to effectively recover the inflation impact (purchasing power gain or loss) on such capital to the extent reflected in the annual cost rate. Any holding gain associated with such capital (monetary liabilities) is therefore, not realizable and is an offset against the "reduction in assets to net recoverable cost." The treatment given herein to the holding gains on monetary liabilities recognizes that prices charged by the Company are designed to recover for such capital no more than any inflation costs factored into the contractual annual cost rate. Thus, the purchasing power adjustment to the tangible assets, which is not realizable and is written off, as well as the increased operating expenses, results in no financial loss to the owners of the Company (the common shareholders) to the extent of the leverage financing.

This information should be viewed as an estimate of the approximate effects of inflation, rather than a precise measure.

The statement of income, adjusted for changing prices reflects adjustments only with respect to electric utility plant—the area of the Company most affected by inflation. All other items are considered to have been effectively transacted at average 1983 price levels, and therefore, do not require adjustment.

Statement of Income from Continuing Operations Adjusted for Changing Prices for the Year Ended December 31, 1983

	As Reported in the Primary Statements	Constant Dollar Average 1983 Dollars	Current Cost Average 1983 Dollars
		(In Thousands)	
Operating revenues	$1,647,183	$1,647,183	$1,647,183
Operating expenses:			
Operation and maintenance:			
Fuel for generation	517,625	524,411	534,488
Other	440,522	440,522	440,522
Depreciation and amortization	148,342	251,059	257,747
Taxes other than on income	114,295	114,295	114,295
Income tax expense	162,443	162,443	162,443
Total operating expenses	1,383,227	1,492,730	1,509,495
Operating income	263,956	154,453	137,688
Other income—net	132,482	132,482	132,482
Income before interest charges	396,438	286,935	270,170
Net interest charges	157,169	157,169	157,169
Income from continuing operations (excluding reduction to net recoverable cost)	$ 239,269	$ 129,766*	$ 113,001
Other adjustments to reflect the effects of changing prices:			
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 63,908
Increase (reduction) in assets to net recoverable cost		$ (48,233)	154,692
Effect of increase in general price level			(250,068)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			$ (31,468)
Adjustment for purchasing power loss by net monetary liabilities		$ 112,342	$ 112,342

*Including the reduction in assets to net recoverable cost, income from continuing operations would have been $81,533

**At December 31, 1983 current cost of property, plant and equipment, net of accumulated depreciation was $6,798,429, while historical cost or net cost recoverable through depreciation was $4,571,206

Five Year Comparison of Selected Financial Data Adjusted for Effects of Changing Prices

	Year Ended December 31,				
	1983	1982	1981	1980	1979
	(In Millions of Average 1983 Dollars Except for Per Share Amounts)				
Operating revenues	$1,647.2	$1,587.7	$1,471.9	$1,300.5	$1,270.8
Historical cost information adjusted for general inflation:					
Income from continuing operations (excluding reduction in assets to net recoverable cost)	$ 129.8	$ 120.5	$ 117.3	$ 92.4	$ 128.3
Income from continuing operations per common share (after preferred stock dividend requirements and excluding reduction in assets to net recoverable cost)	$ 1.40	$ 1.29	$ 1.34	$ 1.08	$ 2.20
Net assets at year-end at net recoverable cost	$1,559.7	$1,492.2	$1,446.7	$1,424.3	$1,356.6
Current cost information:					
Income from continuing operations (excluding reduction in assets to net recoverable cost)	$ 113.0	$ 102.2	$ 104.7	$ 79.7	$ 113.0
Income from continuing operations per common share (after preferred stock dividend requirements and excluding reduction in assets to net recoverable cost)	$ 1.13	$ 0.98	$ 1.10	$ 0.82	$ 1.82
Net assets at year-end at net recoverable cost	$1,559.7	$1,492.2	$1,446.7	$1,424.3	$1,356.6
General information:					
Adjustment for purchasing power loss by net monetary liabilities	$ 112.3	$ 116.9	$ 266.9	$ 368.4	$ 373.9
Cash dividends declared per common share	$ 2.46	$ 2.48	$ 2.54	2.66	$ 2.82
Market price per common share at year-end	$ 21.63	$ 21.94	$ 21.47	$ 20.94	$ 24.82
CPI-U—average	298.4	289.1	272.4	246.8	217.4
—year-end	303.5	292.4	281.5	258.4	229.9

CAROLINA POWER & LIGHT COMPANY

SCHEDULE V - UTILITY PLANT

For the Year Ended December 31, 1983

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Period	Additions at Cost	Retirements	Other Changes - Debits/Credits	Balance at Close of Period
Electric utility plant other than nuclear fuel (at original cost):					
In Service:					
Intangible plant (Note 1)	$ 177,329				$ 177,329
Production plant	1,737,423,357	$521,491,911	$14,794,742	$54,434,825 cr.	2,189,685,701
Transmission plant	445,247,587	94,492,331	1,744,221	2,661,619	540,657,316
Distribution plant	739,187,396	66,854,702	9,442,922	143,043	796,742,219
General plant	90,817,674	11,290,363	3,290,190	2,812 cr.	98,815,035
Electric utility plant in service	3,012,853,343	694,129,307	29,272,075	51,632,975 cr.	3,626,077,600
Electric plant acquisition adjustment	1,790,714	2,551,907		1,757,399	3,548,113
Held for future use	10,350,091	2,551,907			12,901,998
Electric plant purchased or sold	4,496,639	4,496,639 cr.			0
Construction work in progress	1,994,905,675	32,054,196 cr.		265,300,843 cr.	1,697,550,636
Total electric utility plant other than nuclear fuel	5,024,396,462	660,130,379	29,272,075	315,176,419 cr.	5,340,078,347
Nuclear fuel (at original cost)	231,518,038	48,487,841	8,368,347	6,836,043 cr.	264,801,489
Total electric utility plant including nuclear fuel	$5,255,914,500	$708,618,220	$37,640,422	$322,012,462 cr.	$5,604,879,836

NOTES

1. In conformity with the system of accounts prescribed by regulatory authority, intangible assets are included in utility plant, the amount thereof being set forth above, and Schedule VII is omitted.
2. The net change in Column E represents the following:

Electric utility plant other than nuclear fuel:	
Original cost of property sold to Power Agency	$ 63,044,427 cr.
Transfer of Harris Unit No. 2 to Deferred Debits	253,711,533 cr.
Electric Plant acquisition adjustment - VEPCO	1,757,399
Transfer between utility and non-utility property, etc.	177,858 cr.
Total	$315,176,419 cr.
Nuclear fuel:	
Original cost of property sold or subsequently transferred to Power Agency, and adjustments related thereto	$ 8,842,755 cr.
Miscellaneous adjustments	2,006,712
Total	$ 6,836,043 cr.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE V - UTILITY PLANT

For the Year Ended December 31, 1982

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Period	Additions at Cost	Retirements	Other Changes - Debits/Credits	Balance at Close of Period
Electric utility plant other than nuclear fuel (at original cost):					
In Service:					
Intangible plant (Note 1)	$ 177,329				$ 177,329
Production plant	1,817,275,020	$ 45,216,509	$ 5,789,740	$119,278,432 cr.	1,737,423,357
Transmission plant	405,089,391	41,286,349	1,201,296	73,143	445,247,587
Distribution plant	684,880,789	59,512,354	8,122,692	2,916,945	739,187,396
General plant	78,025,241	15,863,690	1,724,810	1,346,447 cr.	90,817,674
Electric utility plant in service	2,985,447,770	161,878,902	16,838,538	117,634,791 cr.	3,012,853,343
Electric plant acquisition adjustment	1,259,208			531,506	1,790,714
Held for future use	10,370,624	73,218		93,751 cr.	10,350,091
Electric plant purchased or sold	3,082,336	1,414,303			4,496,639
Construction work in progress	1,854,176,807	474,917,767		334,188,899 cr.	1,994,905,675
Total electric utility plant other than nuclear fuel	4,854,336,745	638,284,190	16,838,538	451,385,935 cr.	5,024,396,462
Nuclear fuel (at original cost)	254,477,419	16,450,084	19,137,429	20,272,036 cr.	231,518,038
Total electric utility plant including nuclear fuel	$5,108,814,164	$654,734,274	$35,975,967	$471,657,971 cr.	$5,255,914,500
				(Note 2)	

NOTES

1. In conformity with the system of accounts prescribed by regulatory authority, intangible assets are included in utility plant, the amount thereof being set forth above, and Schedule VII is omitted.
2. The net change in Column E represents the following:

Electric utility plant other than nuclear fuel:	
Original cost of property sold to Power Agency	$450,943,859 cr.
Transfer between utility and non-utility property, etc.	442,076 cr.
Total	$451,385,935 cr.
Nuclear fuel:	
Original cost of property sold or subsequently transferred to Power Agency, and adjustments related thereto	$ 20,325,607 cr.
Miscellaneous adjustments	53,571
Total	$ 20,272,036 cr.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE V - UTILITY PLANT

For the Year Ended December 31, 1981

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Period	Additions at Cost	Retirements	Other Changes - Debits/Credits	Balance at Close of Period
Electric utility plant other than nuclear fuel (at original cost):					
In Service:					
Intangible plant (Note 1)	$ 177,329				$ 177,329
Production plant	1,775,613,683	$ 39,439,450	$ 347,223 cr.	$ 1,874,664	1,817,275,020
Transmission plant	375,072,239	31,934,619	2,631,888	714,421	405,089,391
Distribution plant	645,726,714	51,366,379	9,357,600	2,854,704 cr.	684,880,789
General plant	66,585,674	13,403,077	1,770,999	192,511 cr.	78,025,241
Electric utility plant in service	2,863,175,639	136,143,525	13,413,264	458,130 cr.	2,985,447,770
Electric plant acquisition adjustment	1,259,208				1,259,208
Held for future use	10,035,644	254,030		80,950	10,370,624
Electric plant purchased or sold		3,082,336			3,082,336
Construction work in progress	1,616,512,736	409,027,765		171,363,694 cr.	1,854,176,807
Total electric utility plant other than nuclear fuel	4,490,983,227	548,507,656	13,413,264	171,740,874 cr.	4,854,336,745
Nuclear fuel (at original cost)	218,466,220	36,222,905	113,567	98,139 cr.	254,477,419
Total electric utility plant including nuclear fuel	$4,709,449,447	$584,730,561	$13,526,831	$171,839,013 cr. (Note 2)	$5,108,814,164

NOTES

1. In conformity with the system of accounts prescribed by regulatory authority, intangible assets are included in utility plant, the amount thereof being set forth above, and Schedule VII is omitted.
2. The net change in Column E represents the following:

Electric utility plant other than nuclear fuel:

Transfer of Harris Units Nos 3 and 4 and Brunswick Cooling Tower to Deferred Debits	$171,203,454 cr.
Transfer between utility and non-utility property	537,420 cr.
Total	$171,740,874 cr.

Nuclear fuel:

Spent fuel transportation charges transferred to accumulated provision for amortization of nuclear fuel	$ 98,139 cr.
Total	$ 98,139 cr.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE VI - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF ELECTRIC UTILITY PLANT

For the Year Ended December 31, 1983

COLUMN A	COLUMN B	COLUMN C		COLUMN D		COLUMN E
		Additions		Deductions from Reserves		
		(1)	(2)	(1)	(2)	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Retirements, Renewals, & Replacements	Other	Balance at Close of Period
Accumulated provision for depreciation of electric utility plant other than nuclear fuel (Note 1)	$792,012,456	$130,052,281	-0-	$26,282,050	$11,532,494	$884,250,193
Accumulated provision for amortization of nuclear fuel	$131,279,866	$ 30,594,018	-0-	$ 8,368,347	$ 4,081,741	$149,423,796

NOTES

1. This accumulated provision is maintained for all electric utility depreciable plant. For statement of the Company's policy with respect to retirements of property, see Note 1 to Financial Statements. The amounts in Column D(1) include net salvage credits for retirements. Column D (2), for electric utility plant other than nuclear fuel, made up of $11,813,394 for a reserve reversal due to sale of electric plant in service to Power Agency, $50,728 for a transfer to the reserve for non-utility property, and $(331,628) depreciation reserve related to purchase of electric plant in service from Virginia Electric and Power Company; and, for nuclear fuel, is principally related to a reserve reversal due to the sale of nuclear fuel to Power Agency.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE VI - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF ELECTRIC UTILITY PLANT

For the Year Ended December 31, 1982

COLUMN A	COLUMN B	COLUMN C		COLUMN D		COLUMN E
		Additions		Deductions from Reserves		
		(1)	(2)	(1)	(2)	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Retirements, Renewals, & Replacements	Other	Balance at Close of Period
Accumulated provision for depreciation of electric utility plant other than nuclear fuel (Note 1)	$717,799,542	$114,154,540	-0-	$17,797,846	$22,143,780	$792,012,456
Accumulated provision for amortization of nuclear fuel	$144,791,161	$13,536,067	-0-	$19,137,429	$ 7,909,933	$131,279,866

NOTES

1. This accumulated provision is maintained for all electric utility depreciable plant. For statement of the Company's policy with respect to retirements of property, see Note 1 to Financial Statements. The amounts in Column D(1) include net salvage credits for retirements. Column D (2), for electric utility plant other than nuclear fuel, made up of $22,959,195 for a reserve reversal due to sale of electric plant in service to Power Agency, $20,311 for a transfer to the reserve for non-utility property, and $(835,726) depreciation reserve related to purchase of electric plant in service from Pinehurst, Incorporated; and, for nuclear fuel, is principally related to a reserve reversal due to the sale of nuclear fuel to Power Agency.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE VI - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF ELECTRIC UTILITY PLANT

For the Year Ended December 31, 1981

COLUMN A	COLUMN B	COLUMN C		COLUMN D		COLUMN E
		Additions		Deductions from Reserves		
		(1)	(2)	(1)	(2)	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Retirements, Renewals, & Replacements	Other	Balance at Close of Period
Accumulated provision for depreciation of electric utility plant other than nuclear fuel (Note 1)	$627,407,874	$105,036,153	-0-	$14,587,189	$ 57,296	$717,799,542
Accumulated provision for amortization of nuclear fuel	$106,597,818	$38,405,161	-0-	$ 113,567	$ 98,251	$144,791,161

NOTES

1. This accumulated provision is maintained for all electric utility depreciable plant. For statement of the Company's policy with respect to retirements of property, see Note 1 to Financial Statements. The amounts in Column D(1) include net salvage credits for retirements. Column D (2) is a transfer to the reserve for non-utility property.

CAROLINA POWER & LIGHT COMPANY

VIII - RESERVES

For the Year Ended December 31, 1983

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves, deducted from related assets on the balance sheet - Uncollectible accounts	$ 1,756,586	*	*	*	$ 2,477,369
Reserves other than those deducted from assets on the balance sheet: Injuries and damages	$ 1,947,293	*	$ *	*	$ 2,217,604
Property insurance reserve	$ 4,256,420	-0-	$ 712,882	-0-	$ 4,969,302
Reserve for possible coal mine investment losses**	$ -0-	$32,000,000	$ -0-	$ -0-	$ 32,000,000

* This information is omitted in accordance with Rule 12-13 of Regulation S-X of the Securities and Exchange Commission, since the additions, deductions and balances are not significant.

** See Note 2 to Financial Statements.

CAROLINA POWER & LIGHT COMPANY

VIII - RESERVES

For the Year Ended December 31, 1982

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves, deducted from related assets on the balance sheet - Uncollectible accounts	$ 1,532,729	*	*	*	$ 1,756,586
Reserves other than those deducted from assets on the balance sheet: Injuries and damages	$ 1,625,939	*	$ *	*	$ 1,947,293
Property insurance reserve	$ 3,961,291	-0-	$ 295,129	-0-	$ 4,256,420
Reserve for possible refund of revenues, net	$ 24,592,951	$24,698,860	$ 31,520	$48,823,904	$ 499,427

* This information is omitted in accordance with Rule 12-13 of Regulation S-X of the Securities and Exchange Commission, since the additions, deductions and balances are not significant.

CAROLINA POWER & LIGHT COMPANY

VIII - RESERVES

For the Year Ended December 31, 1981

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves, deducted from related assets on the balance sheet - Uncollectible accounts	$ 1,739,560	*	*	*	$ 1,532,729
Reserves other than those deducted from assets on the balance sheet: Injuries and damages	$ 1,418,045	*	$ *	*	$ 1,625,939
Property insurance reserve	$ 3,473,739	-0-	$ 487,552	-0-	$ 3,961,291
Reserve for possible refund of revenues, net	$ 7,794,531	$16,798,420	-0-	-0-	$ 24,592,951

* This information is omitted in accordance with Rule 12-13 of Regulation S-X of the Securities and Exchange Commission, since the additions, deductions and balances are not significant.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE IX - SHORT-TERM BORROWINGS

For the Three Years Ended December 31, 1983

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Category of aggregate short-term borrowings*	Balance at end of period	Weighted average interest rate	Maximum amount outstanding during the period	Average amount during the period **	Weighted average** interest rate during the period
	For the Year Ended December 31,1983				
Bank loans	-0-	-0-	$ 37,000,000	$ 1,586,301	5.75%
Commercial paper***	$153,200,000	9.70%	$198,550,000	$111,095,969	9.22%
	For the Year Ended December 31, 1982				
Bank loans	$ 13,000,000	9.71%	$ 38,000,000	$ 1,334,247	2.94%
Commercial paper***	$146,575,000	8.66%	$266,400,000	$216,245,066	12.86%
	For the Year Ended December 31, 1981				
Bank loans	$ 17,000,000	2.65%	$ 44,000,000	$ 8,706,022	13.09%
Commercial paper***	$239,250,000	12.14%	$239,250,000	$134,855,793	16.49%

* General terms:
The outstanding bank loans represented demand notes or notes due within 20 days after the end of the year. The commercial paper at the end of the period had due dates of up to 104 days after the end of the period.

Excluded from aggregate short-term borrowings are miscellaneous notes which had balances at year end for 1981-1983 of $3,655,624, $2,635,219 and $2,488,230 respectively.

** Average computed on a daily weighted basis.

*** Includes $130,000,000 ($72,985,000 at December 31, 1983) backed by long-term credit facilities to 9/24/86 and classified as long-term debt.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE X SUPPLEMENTARY INCOME STATEMENT INFORMATION

	For the years ended December 31,		
	(Thousands of Dollars)		
Taxes-Other than on income taxes:	1983	1982	1981
Ad valorem	$ 28,296	$ 29,117	$ 26,964
State and city franchise	83,356	76,787	70,947
Federal and state social security	15,467	13,457	10,713
Miscellaneous	425	404	263
Total	127,544	119,765	108,887
Less-Amount charged to plant and sundry accounts	13,249	15,465	11,599
Remainder-charged to operating expenses	$114,295	$104,300	$ 97,288

Maintenance and repairs other than amounts set out separately in the statements of income are not significant.

ITEM 9. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There has been no change of the Company's accountants within the twenty-four months prior to the date of the financial statements set forth in ITEM 8.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

a) Information on the Company's directors is set forth in the Company's 1984 definitive proxy statement dated April 4, 1984 and incorporated by reference herein.

b) Executive Officers of the Company

Name	Age	Recent Business Experience
Sherwood H. Smith, Jr.	49	Chairman of the Board, President and Chief Executive Officer, May 1980 to present; President and Chief Executive Officer, September 1979; President and Chief Administrative Officer, December 1976. Member of the Board of Directors of the Company since 1971.
William E. Graham, Jr.	54	Executive Vice President, May 1982 to present; Executive Vice President and General Counsel, May 1981; Senior Vice President and General Counsel, December 1976. Member of the Board of Directors since 1980.
Edward G. Lilly, Jr.	58	Executive Vice President and Chief Financial Officer, May 1981 to present; Senior Vice President, Chief Financial Officer, March 1979; Senior Vice President, Chief Financial Officer and Treasurer, September 1978; Senior Vice President and Chief Financial Officer, December 1976. Member of the Board of Directors of Company since 1971.
Edwin E. Utley	59	Executive Vice President, May 1979 to present; Senior Vice President and Group Executive for Power Supply, December 1976. Member of Board of Directors since 1982.
Charles D. Barham, Jr.	53	Senior Vice President and General Counsel, Legal and Regulatory Group, May 1982 to present; Vice President and Senior Counsel, December 1980; private law practice, 1974.

James M. Davis, Jr.	47	Senior Vice President - Operations Support Group, August 1983 to present; Senior Vice President - Fuel and Materials Management Group, December 1980; Vice President and Group Executive - Fuel and Materials Management, May 1979; Manager of Rates and Service Practices, November 1977.
Lynn W. Eury	46	Senior Vice President - Fossil Generation and Power Transmission Group, August 1983 to present; Senior Vice President - Power Supply Group, December 1980; Vice President and Group Executive, May 1980; Vice President - System Planning and Coordination, May 1979; Manager of System Operations and Maintenance, January 1972.
Russell H. Lee	44	Senior Vice President, Customer and Operating Service Group, September 1982 to present; Vice President - Eastern Division, September 1980; Division General Manager, June 1978; District Manager, January 1976.
M. A. McDuffie	59	Senior Vice President - Nuclear Generation Group, August 1983 to present; Senior Vice President - Engineering and Construction Group, December 1976.
Wilson W. Morgan	57	Senior Vice President - Corporate Services Group, May 1979 to present; Vice President - System Planning and Coordination, December 1976.
Samuel Behrends, Jr.	60	Vice President - Corporate Regulatory Policy, December 1976 to present.
Paul S. Bradshaw	46	Vice President and Controller, March 1980 to present; Controller and Chief Accounting Officer, December 1976.
Alan B. Cutter	49	Vice President - Nuclear Engineering and Licensing, August 1983 to present; Vice President - Nuclear Plant Engineering, March 1981; Manager, Nuclear Plant Engineering, April 1980; Manager, Projects Operations with Westinghouse Electric Corporation, October 1976 to April 1980.

R. Thomas Dwyer, III	38	Vice President - Performance Review and Audit Services, May 1983 to present; Manager, Performance Review and Audit Services, September 1978; Audit Manager, Deloitte Haskins & Sells until September 1978.
Norris L. Edge	52	Vice President - Rates and Service Practices, December 1980 to present; Manager of Rates and Service Practices, June 1979; Assistant Manager, Rates and Service Practices, January 1977.
Thomas S. Elleman	52	Vice President - Nuclear Safety and Research, May 1979 to present; Department Head, Nuclear Engineering Department, North Carolina State University, July 1974.
B. J. Furr	46	Vice President - Operations Training and Technical Services, August 1983 to present; Vice President - Nuclear Operations, September 1979; Manager of Generation, May 1976.
Cecil L. Goodnight	41	Vice President - Employee Relations, May 1983 to present; Manager, Employee Relations, August 1980; Assistant to Vice President - Employee Relations prior to August 1980.
P. W. Howe	55	Vice President - Brunswick Nuclear Project, December 1982 to present; Vice President - Technical Services, December 1976.
Richard E. Jones	46	Vice President and Senior Counsel, and Manager, Legal Department, May 1982 to present; Associate General Counsel, January 1975.
William B. Kincaid	63	Vice President - Materials Management, November 1979 to retirement date, March 1, 1984; Vice President, Power Plant Engineering, September 1973.
Mendall H. Long	63	Vice President - Special Projects, October 1, 1981 to present; Manager, Fossil Plant Engineering Support, January 1977.

Jack B. McGirt	59	Vice President - Fossil Generation, August 1983 to present; Vice President - Fossil Operations, December 1980; Manager, Fossil Operations, November 1979; Manager of Fossil and Hydro Section, November 1977.
Bobby L. Montague	48	Vice President - Planning & Coordination, June 1981 to present; Manager System Planning & Coordination, May 1980; Director, Project Analysis, July 1978; Manager, Energy Services, December 1976.
Albert L. Morris, Jr.	59	Vice President - Corporate Communications, December 1976 to present.
E. S. Noell	56	Vice President - Transmission, May 1981 to present; Manager, Transmission System Engineering and Construction, October 1976.
Sheldon D. Smith	63	Vice President - Nuclear Plant Construction, May 1979 to present; Manager of Power Plant Construction, September 1976.
Earl F. Stephenson	59	Vice President - Customer Service Operations Support, December 1976 to present.
R. A. Watson	50	Vice President - Harris Nuclear Project, August 1983 to present; Vice President - Fuel Department, March 1980; Manager, Fuel Department, May 1977.
J. L. Lancaster, Jr.	58	Secretary and Manager of Corporate Insurance, July 1973 to present.
L. T. Quarles	39	Treasurer, March 1979 to present; Assistant Treasurer and Manager of Tax, Cash, Pensions and Bank Relations, November 1977.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in the Company's 1984 definitive proxy statement dated April 4, 1984 and incorporated by reference herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

a) The Company knows of no persons who are beneficial owners of more than five percent of any class of the Company's voting securities.

b) Information on security ownership of the Company's management is set forth in the Company's 1984 definitive proxy statement dated April 4, 1984 and incorporated by reference herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on certain relationships and transactions is set forth in the Company's 1984 definitive proxy statement dated April 4, 1984 and incorporated by reference herein.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

a) 1. Financial Statements Filed:

See ITEM 8 - Financial Statements and Supplementary Data.

2. Financial Statement Schedules:

See ITEM 8 - Financial Statements and Supplementary Data.

3. Exhibits Filed:

Exhibit No. *3a(1)	Restated Charter of Carolina Power & Light Company, dated May 22, 1980 (filed as Exhibit 2(a)(1), File No. 2-64193).
Exhibit No. 3a(2)	By-laws of the Company as amended March 21, 1984.
Exhibit No. *3a(3)	Resolution of Board of Directors, dated December 8, 1954, authorizing the issuance of, and establishing the series designation, dividend rate and redemption prices for the Company's Serial Preferred Stock, $4.20 Series (filed as Exhibit 3a(2) to Form 10-K for year ended December 31, 1980, File No. 1-3382)
Exhibit No. *4a(2)	Resolution of Board of Directors, dated January 17, 1967, authorizing the issuance of, and establishing the series designation, dividend rate and redemption prices for the Company's Serial Preferred Stock, $5.44 Series (filed as Exhibit 3a(3) to Form 10-K for year ended December 31, 1980, File No. 1-3382)
Exhibit No. *4a(3)	Statement of Classification of Shares dated May 7, 1970, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for the Company's Serial Preferred Stock, $9.10 Series (filed as Exhibit 3a(4) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(4)	Statement of Classification of Shares dated January 13, 1971, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for the Company's Serial Preferred Stock, $7.95 Series (filed as Exhibit 3a(5) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(5)	Statement of Classification of Shares dated September 7, 1972, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for the Company's Serial Preferred Stock, $7.72 Series (filed as Exhibit 3a(6) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(6)	Statement of Classification of Shares dated October 23, 1973, relating to the relative rights and preferences of the Company's Preferred Stock A, $7.45 Series (filed as Exhibit 3a(7) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(7)	Statement of Classification of Shares dated February 22, 1974, relating to the relative rights and preferences of the Company's Serial Preferred Stock, $8.48 Series (filed as Exhibit 3a(8) to Form 10-K for year ended December 31, 1980, File No. 1-3382).

Exhibit No. *4a(8)	Statement of Classification of Shares dated March 13, 1975, relating to the relative rights and preferences of the Company's $2.675 Preference Stock, Series A (filed as Exhibit 3a(9) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(9)	Statement of Classification of Shares dated September 7, 1979, relating to the relative rights and preferences of the Company's Preferred Stock A, $8.75 Series (filed as Exhibit 3a(10) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(10)	Statement of Classification of Shares dated February 20, 1980, relating to the relative rights and preferences of the Company's Prefer ed Stock A, $9.25 Series (filed as Exhibit 3a(11) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(11)	Statement of Classification of Shares dated August 29, 1980, relating to the relative rights and preferences of the Company's Serial Preferred Stock, $11.16 Series (filed as Exhibit 3a(12) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(12)	Statement of Classification of Shares dated September 15, 1980, relating to the relative rights and preferences of the Company's Preferred Stock A, $9.00 Series (filed as Exhibit 3a(13) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(13)	Statement of Classification of Shares dated May 1, 1981, relating to the relative rights and preferences of the Company's Serial Preferred Stock, $14.00 Series (filed as Exhibit 3a(14) to Form 10-K for year ended December 31, 1981, File No. 1-3382).
Exhibit No. *4a(14)	Preferred Stock Purchase Agreement dated October 23, 1973 relating to Preferred Stock A, $7.45 Series (filed as Exhibit 4a(1) to Form 10-K for year ended December 31, 1980, File No. 1-3382).
Exhibit No. *4a(15)	Preferred Stock Purchase Agreement dated September 1, 1979 relating to Preferred Stock A, $8.75 Series (filed as Exhibit II-A to Form 10-Q for Quarter Ended September 30, 1979).
Exhibit No. *4a(16)	Preferred Stock Purchase Agreement dated February 18, 1980 relating to Preferred Stock A, $9.25 Series (filed as Exhibit II-A to Form 10-Q for Quarter Ended March 31, 1980).

Exhibit No. *4a(17)	Preferred Stock Purchase Agreement dated September 15, 1980 relating to Preferred Stock A, $9.00 Series (filed as Exhibit 4(a) to Form 10-Q for Quarter Ended September 30, 1980).
Exhibit No. *4b(18)	Mortgage and Deed of Trust dated as of May 1, 1940 between the Company and Irving Trust Company and Frederick G. Herbst (D. W. May, Successor), Trustees and the First through Fifth Supplemental Indentures thereto (Exhibit 2(b), File No. 2-64189); and the Sixth through Thirtieth Supplemental Indentures (Exhibit 2(b)-5, File No. 2-16210; Exhibit 2(b)-6, File No. 2-16210; Exhibit 4(b)-8, File No. 2-19118; Exhibit 4(b)-2, File No. 22439; Exhibit 4(b)-2, File No. 2-24624; Exhibit 2(c), File No. 2-27297; Exhibit 2(c), File No. 2-30172; Exhibit 2(c), File No. 2-35694; Exhibit 2(c), File No. 2-37505; Exhibit 2(c), File No. 2-39002; Exhibit 2(c), File No. 2-41738; Exhibit 2(c), File No. 2-43439; Exhibit 2(c), File No. 2-47751; Exhibit 2(c), File No. 2-49347; Exhibit 2(c), File No. 2-53113; Exhibit 2(d), File No. 2-53113; Exhibit 2(c), File No. 2-59511; Exhibit 2(c) File No. 2-61611; Exhibit 2(d), File No. 2-64189; Exhibit 2(c), File No. 2-65514; Exhibit 2(c), File No. 2-66851; Exhibit 2(d), File No. 2-66851; Exhibit 4(b)-1, File No. 2-891299; Exhibit 4(b)-2, File No. 2-81299 and Exhibit 4(b)-3, File No. 2-81299.
Exhibit No. 4b(19)	Thirty-first Supplemental Indenture dated as of March 15, 1983.
Exhibit No. 4b(20)	Thirty-second Supplemental Indenture dated as of March 15, 1983.
Exhibit No. 4b(21)	Thirty-third Supplemental Indenture dated as of December 1, 1983.
Exhibit No. 4b(22)	Thirty-fourth Supplemental Indenture dated as of December 15, 1983.
Exhibit No. *10a(1)	Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letter dated February 18, 1982, and amendment dated February 24, 1982 (filed as Exhibit 10(a)(1) to Form 10-K for year ended December 31, 1981, File No. 1-3382).
Exhibit No. *10a(2)	Operating and Fuel Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 15, 1981 changing name to

North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10a(2) to Form 10-K for year ended December 31, 1981, File No. 1-3382).

Exhibit No. *10a(3)	Power Coordination Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982 (filed as Exhibit 10a(3) to Form 10-K for year ended December 31, 1981, File No. 1-3382).
Exhibit No. *10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and Power Agency (filed as Exhibit 10a(4) to Form 10-K for the year ended December 31, 1982, File No. 1-3382.)
Exhibit No. *10c(1)	Directors Deferred Compensation Plan effective January 1, 1982 as amended January 1, 1983 (filed as Exhibit 10c(1) to Form 10-K for year ended December 31, 1981 and Exhibit No. 10c(4) to Form 10-K for the year ended December 31, 1982, File No. 1-3382.)
Exhibit No. 10c(2)	Supplemental Executive Retirement Plan effective January 1, 1984.
Exhibit No. *10c(3)	Retirement Plan for Outside Directors (filed as Exhibit 10c(3) to Form 10-K for year ended December 31, 1981, File No. 1-3382).
Exhibit No. *10c(4)	Executive Deferred Compensation Plan effective May 1, 1982 and amendment thereto effective January 1, 1983 filed as Exhibit No. 10c(5) to Form 10-K for year ended December 31, 1982, File No. 1-3382.)
Exhibit No. 10c(5)	Senior Management Deferred Compensation Plan.
Exhibit No. 12	Computation of Ratio of Earnings to Fixed Charges.
Exhibit No. 24a	Consent of Deloitte Haskins & Sells
Exhibit No. 24b	Consent of Paul Weir Company Incorporated

*Incorporated herein by reference as indicated.

(b) Reports on Form 8-K filed during or with respect to the last quarter of 1983:

Date of Report	Item Reported	
October 13, 1983	Item 5.	Other Events
October 21, 1983	Item 5.	Other Events
	Item 7.	Financial Statements, Pro Forma Financial Information and Exhibits. (Filing included Interim Financial Statements for the quarter ended September 30, 1983).
November 30, 1983	Item 2.	Acquisition or Disposition of Assets
	Item 5.	Other Events
	Item 7.	Financial Statements, Pro Forma Financial Information and Exhibits (Filing included no financial statements).
December 16, 1983	Item 5.	Other Events
	Item 7.	Financial Statements, Pro Forma Financial Information and Exhibits (Filing included no financial statements).
December 21, 1983	Item 5.	Other Events
	Item 7.	Financial Statements, Pro Forma Financial Information and Exhibits (Filing included no financial statements).
January 16, 1984 (for the month of December, 1983.)	Item 5.	Other Events

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 23rd day of March, 1984.

CAROLINA POWER & LIGHT COMPANY
(Registrant)

By /s/ Paul S. Bradshaw
Paul S. Bradshaw
Vice President and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ Sherwood H. Smith, Jr. (Sherwood H. Smith, Jr. Chairman of the Board, President and Chief Executive Officer)	Principal Executive Officer and Director	
/s/ Edward G. Lilly, Jr. (Edward G. Lilly, Jr. Executive Vice President)	Principal Financial Officer and Director	
/s/ Paul S. Bradshaw (Paul S. Bradshaw Vice President and Controller)	Principal Accounting Officer	
/s/ Daniel D. Cameron, Sr. (Daniel D. Cameron, Sr.)	Director	March 23, 1984
/s/ Felton J. Capel (Felton J. Capel)	Director	
(George H. V. Cecil)	Director	
/s/ Charles W. Coker, Jr. (Charles W. Coker, Jr.)	Director	
/s/ William E. Graham, Jr. (William E. Graham, Jr.)	Director	
(Margaret T. Harper)	Director	

Signature	Title	Date
/s/ L. H. Harvin, Jr. (L. H. Harvin, Jr.)	Director	
(Karl G. Hudson, Jr.)	Director	
(John G. Medlin, Jr.)	Director	March 23, 1984
/c/ A. C. Monk, Jr. (A. C. Monk, Jr.)	Director	
(Horace L. Tilghman, Jr.)	Director	
/s/ E. E. Utley (E. E. Utley)	Director	