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50-324 Brunswick Steam Electric Plant, Unit 2, Carolina Powe 05000324
50-325 Brunswick Steam Electric Plant, Unit 1, Carolina Powe 05000325
50-400 Shearon Harris Nuclear Power Plant, Unit 1, Carolina 05000400

AUTH.NAME AUTHOR AFFILIATION
MORTON,T.C. Carolina Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
COLLINS,S.J.

See Report

SUBJECT: Provides evidence of payment that util maintains guarantee of payment of deferred premiums in amount of $10 million for each reactor,per 10CFR140.21.

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TITLE: Insurance: Indemnity/Endorsement Agreements

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CP&L

10 CFR 140.21

Carolina Power & Light Company
PO Box 1551
411 Fayetteville Street Mall
Raleigh NC 27602

April 23, 1999

PE&RAS-99-032

United States Nuclear Regulatory Commission
ATTENTION: Samuel J. Collins
Director of Nuclear Reactor Regulation
Washington, DC 20555

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324 / LICENSE NOS. DPR-71 AND DPR-62

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / LICENSE NO. NPF-63

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261 / LICENSE NO. DPR-23

SUBJECT: **SUBMITTAL OF LICENSEE GUARANTEES OF PAYMENT OF DEFERRED PREMIUMS**

Dear Mr. Collins:

In accordance with 10 CFR 140.21, Carolina Power & Light (CP&L) Company is providing evidence that it maintains a guarantee of payment of deferred premiums in the amount of $10 million for each of our reactors. Enclosed is a copy of CP&L's annual financial statement of operations for fiscal year 1998 (i.e. Form 10K), certified by an independent auditor. Page 51 describes the Company's cash flow in 1998. Also enclosed is the projected cash flow statement for 1999, certified by the Company's Vice President - Treasury and Treasurer, which indicates that CP&L projects sufficient cash flow for 1999 to provide for payment of retrospective premiums within three (3) months after submission of this statement. This statement is submitted by April 30 of each year.

North Carolina Eastern Municipal Power Agency is the owner of 18.33% of the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2, and 16.17% of the Harris Nuclear Power Plant. This submittal provides evidence of a guarantee of payment of deferred premiums of both CP&L and the North Carolina Eastern Municipal Power Agency. No new commitments have been made in this submittal.

Sincerely,

Terry C. Morton

Terry C. Morton
Manager - Performance Evaluation & Regulatory Affairs

030046

M001

Enclosures as stated

9905030152 990423
PDR ADOCK 05000261
P PDR

cc: NRC Document Control Desk (with enclosures)
Mr. L. A. Reyes, Regional Administrator - Region II
Mr. J. B. Brady, USNRC Senior Resident Inspector - SHNPP, Unit No. 1
USNRC Resident Inspector - HBRSEP, Unit No. 2
Mr. R. J. Laufer, NRR Project Manager - SHNPP, Unit No. 1
Mr. T. A. Easlick, USNRC Senior Resident Inspector - BSEP, Unit Nos. 1 and 2
Chair J. A. Sanford - North Carolina Utilities Commission
Mr. R. Subbaratnam, NRR Project Manager - HBRSEP, Unit No. 2
Mr. A. G. Hansen, NRR Project Manager - BSEP, Unit Nos. 1 and 2

CAROLINA POWER & LIGHT COMPANY
FINANCIAL FORECAST
NET CASH PROVIDED BY OPERATING ACTIVITIES, LESS DIVIDENDS
(Millions of dollars)

Cash Flows	Actual 1998	Projected 1999
Operating Activities		
Earnings and other net changes, including interest and dividends paid	$ **104**	$ 207
Depreciation and amortization	**582**	591
Deferred income taxes	**(39)**	(60)
Investment tax credit	**(10)**	(10)
Allowance for equity funds used during construction	-	(17)
Net cash provided by operating activities, less dividends	$ **637**	$ 711

Average Quarterly Cash Flow	$ 159	$ 178
Maximum total contingent liability ($10 million per reactor)	$ 40 *	

* Includes $5,283,000 applicable to the 18.33% and 16.17% ownership interest of the North Carolina Eastern Municipal Power Agency in the Brunswick Units and Harris Unit, respectively.

The above forecast information is based upon assumptions concerning many variables and is subject to significant changes. Accordingly, such information represents estimates and will be updated periodically. This information is provided for general information purposes only and not for any specific use or reliance.

I have examined the foregoing statement of Net Cash Provided by Operating Activities, Less Dividends and certify that it fairly presents the internal cash flow position of Carolina Power & Light Company for the twelve-month period ending December 31, 1999.

Mark F. Mulhern

Mark F. Mulhern
Vice President and Treasurer

Sworn to and subscribed before me
this 8th day of April, 1999.

"OFFICIAL SEAL"
Notary Public, North Carolina
County of Johnston
Peggy Holton
My Commission Expires 6/25/2001

Peggy Holton

My commission expires: 6-25-2001

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1998

OR

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

For the transition period from ____________ to ____________

Commission file number 1-3382

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

North Carolina	56-0165465	411 Fayetteville Street Raleigh, North Carolina	27601
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices)	(Zip Code)

919-546-6111
(Registrant's telephone number, including area code)

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
Quarterly Income Capital Securities	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 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 _____.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of the voting and non-voting common stock held by non-affiliates at February 26, 1999, was $6,034,582,932.

Shares of Common Stock (Without Par Value) outstanding at February 26, 1999: 151,337,503.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's 1999 definitive proxy statement dated April 1, 1999, are incorporated into Part III, Items 10, 11, 12 and 13 hereof.

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SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The matters discussed throughout this Form 10-K that are not historical facts are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Examples of forward-looking statements discussed in this Form 10-K, PART I, ITEM 1, "BUSINESS", include, but are not limited to, statements under the following headings: 1) "General" relating to forecasted capacity margins over anticipated system peak loads; 2) "Generating Capability" regarding the forecasted system sales growth and planned generation additions schedule; 3) "Interconnections with Other Systems" relating to future energy cost savings resulting from amendments to agreements with Cogentrix and relating to estimated minimum annual payments for long-term purchase contracts; 4) "Competition" regarding the effect on the Company of increased competition at the wholesale level and the likelihood of additional industry restructuring-related bills being introduced in Congress in 1999; 5) "Capital Requirements" relating to estimated capital requirements for 1999-2001; 6) "Financing Program" relating to expected external funding requirements; 7) "Environmental Matters" relating to future capital expenditures to meet nitrogen oxide emission requirements, emerging regulatory requirements and the materiality of future costs related to environmental matters; 8) "Nuclear Matters" relating to future capital expenditures for modifications at the Company's nuclear units, future increase in low-level radioactive waste disposal costs, materiality of various nuclear-related matters; 9) "Fuel" regarding the percentages of future coal burn requirements from intermediate and long-term agreements, effect of amendments to the Clean Air Act on the price of low sulfur coal, sufficiency of existing uranium contracts and regarding total decontamination and decommissioning fund fees expected to be paid; and 10) "Diversified Businesses" relating to future services to be provided by Interpath Communications, Inc., and Strategic Resource Solutions Corp.'s enhanced ability to deliver energy-management products.

In addition, examples of forward-looking statements discussed in this Form 10-K, PART II, ITEM 7, "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS", include, but are not limited to, statements under the following headings: 1) "Liquidity and Capital Resources" about estimated capital requirements through the year 2001 and 2) "Other Matters" about the effects of new environmental regulations, nuclear decommissioning costs, the effect of electric utility industry restructuring and the outcome of the Year 2000 compliance.

Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that should be considered with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: Governmental policies and regulatory actions (including those of the Federal Energy Regulatory Commission, the Environmental Protection Agency, the Nuclear Regulatory Commission, the Department of Energy, the North Carolina Utilities Commission and the South Carolina Public Service Commission); general industry trends; operation of nuclear power facilities; availability of nuclear waste storage facilities; nuclear decommissioning costs; changes in the economy of areas served by the Company; legislative and regulatory initiatives that impact the speed and degree of industry restructuring; ability to obtain adequate and timely rate recovery of costs, including potential stranded costs arising from industry restructuring; competition from other energy suppliers; the success of the Company's diversified businesses; ability of the Company and its suppliers and customers to successfully address Year 2000 readiness issues; weather conditions and catastrophic weather-related damage; market demand for energy; inflation; capital market conditions; unanticipated changes in operating expenses and capital expenditures; and legal and administrative proceedings. All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond the control of the Company. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the effect of each such factor on the Company.

PART I

ITEM 1. BUSINESS

GENERAL

1. *Company*. Carolina Power & Light Company (the Company) is a public service corporation formed under the laws of North Carolina in 1926, and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. The Company had approximately 7,200 employees at December 31, 1998. The principal executive offices of the Company are located at 411 Fayetteville Street, Raleigh, North Carolina 27601, telephone number: 919-546-6111.

2. *Franchises.* The Company is a regulated public utility and holds franchises to the extent necessary to operate in the municipalities and other areas it serves.

3. *Service*. The territory served, an area of approximately 30,000 square miles, includes a substantial portion of the coastal plain of North Carolina extending to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in northeastern 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 3.9 million.

   The Company provides retail electricity in over 200 communities, each having an estimated population of 500 or more, and at wholesale to North Carolina Eastern Municipal Power Agency (Power Agency) consisting of 32 members, 3 municipalities, French Broad Electric Membership Corporation and North Carolina Electric Membership Corporation (NCEMC) consisting of 27 members (17 of which are served by the Company's system). At December 31, 1998, the Company was furnishing electric service to approximately 1,183,000 customers.

4. *Sales*. During 1998, 33% of operating revenues were derived from residential sales, 22% from commercial sales, 23% from industrial sales, 13% from wholesale sales and 9% from other sources. Of such operating revenues, approximately 67% were derived from North Carolina retail customers, 13% from South Carolina retail customers, 13% from North Carolina wholesale customers, less than 1% from South Carolina wholesale customers and 6% from sales to other utilities and other customers.

5. *Peak Demand*. A 60-minute system peak demand record of 10,529 megawatts (MW) was reached on July 23, 1998. At the time of this peak demand, the Company's capacity margin, based on installed capacity (less unavailable capacity) and scheduled firm purchases and sales, was approximately 7.6%.

   Total system peak demand decreased for 1996 by 3.4%, for 1997 increased by 2.2%, and for 1998 increased by 5.0% as compared with the preceding year. The Company currently projects that system peak demand will increase at an average annual growth rate of approximately 2.8% over the next ten years. The year-to-year change in actual peak demand is influenced by the specific weather conditions during those years and may not exhibit a consistent pattern. Total system load factors, expressed as the ratio of the average load supplied to the peak load demand, were 60.8% for 1996, 60.6% for 1997, and 60.1% for 1998. The Company forecasts capacity margins of 10.8% over anticipated system peak load for 1999 and 11% for 2000. This forecast assumes normal weather conditions in each year consistent with long-term experience, and is based upon the rated Maximum Dependable Capacity of generating units in commercial operation and scheduled firm purchases of power. See PART I, ITEM 1, "Generating Capability" and "Interconnections With Other Systems". However, some of the generating units included in arriving at

these capacity margins may be unavailable as a result of scheduled and unplanned outages. See PART I, ITEM 1, "Nuclear Matters". The data contained in this paragraph includes Power Agency's load requirements and capability from its ownership interests in certain of the Company's generating facilities. See PART I, ITEM 1, "Generating Capability", paragraph 1.

GENERATING CAPABILITY

1. *Facilities.* At December 31, 1998, the Company had a total system installed generating capability (including Power Agency's share) of 9,963 MW, with generating capacity provided primarily from the installed generating facilities listed in the table below. The remainder of the Company's generating capacity is composed of 53 coal, hydro and combustion turbine units ranging in size from a 2.5 MW hydro unit to a 78 MW coal-fired unit. Pursuant to certain agreements with the Company, Power Agency has acquired undivided ownership interests of 18.33% in Brunswick Unit Nos. 1 and 2, 12.94% in Roxboro Unit No. 4 and 16.17% in Harris Unit No. 1 and Mayo Unit No. 1. Of the total system installed generating capability of 9,963 MW, 53% is coal, 32% is nuclear, 2% is hydro and 13% is fired by other fuels including No. 2 oil, natural gas and propane.

MAJOR INSTALLED GENERATING FACILITIES
AT DECEMBER 31, 1998

Plant Location	Unit No.	Year Commercial Operation	Primary Fuel	Maximum Dependable Capacity
Asheville	1	1964	Coal	198 MW
(Skyland, N.C.)	2	1971	Coal	194 MW
Cape Fear	5	1956	Coal	143MW
(Moncure, N.C.)	6	1958	Coal	173MW
Darlington County Plant	12	1997	Gas/Oil	120MW
(Hartsville, S.C.)	13	1997	Gas/Oil	120MW
H.F. Lee	1	1952	Coal	79MW
(Goldsboro, N.C.)	2	1951	Coal	76MW
	3	1962	Coal	252MW
H.B. Robinson	1	1960	Coal	174MW
(Hartsville, S.C.)	2	1971	Nuclear	683MW
Roxboro	1	1966	Coal	385MW
(Roxboro, N.C.)	2	1968	Coal	670MW
	3	1973	Coal	707MW
	4	1980	Coal	700MW*
L.V. Sutton	1	1954	Coal	97MW
(Wilmington, N.C.)	2	1955	Coal	106MW
	3	1972	Coal	410MW

Brunswick (Southport, N.C.)	1	1977	Nuclear	820MW*
	2	1975	Nuclear	811MW*
Mayo (Roxboro, N.C.)	1	1983	Coal	745MW*
Harris (New Hill, N.C.)	1	1987	Nuclear	860MW*

* Facilities are jointly owned by the Company and Power Agency, and the capacity shown includes Power Agency's share.

2. ***Maintenance of Properties***. 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 combustion turbine units and hydro units) is approximately 40 years from the date of commercial operation.

3. ***Generation Additions Schedule***. The Company's energy and load forecasts were revised in December 1998. Over the next ten years, system internal sales growth is forecasted to average approximately 2.8% per year and annual growth in system internal peak demand is projected to average approximately 2.8%. The Company's generation additions schedule provides for the addition of approximately 2,800 MW of combustion turbine capacity and 2,500 MW of combined cycle capacity over the period 1999 to 2008 in order to meet the needs of its growing customer base and increase its ability to participate in the wholesale power market. The Company may alter its long-term plans based on changes in load forecasts, market conditions, and other factors. In addition, see Part I, Item 1 "Interconnections with Other Systems" for discussion of the Company's long-term purchase power contracts.

On August 18, 1998 the Company filed with the North Carolina Utility Commission (NCUC) an Application for a Certificate of Public Convenience and Necessity to construct an additional 177 MW of combustion turbine capacity adjacent to the Company's Lee Steam Electric Plant in Wayne County, North Carolina and a second 160 MW combustion turbine unit at the Company's Asheville Steam Electric Plant in Buncombe County, North Carolina. The Wayne County Turbine is in addition to the 500 MW of combustion turbine capacity for which the Company received a Certificate of Public Convenience and Necessity on March 21, 1996. These units will primarily be used during periods of summer and winter peak demands. By order issued December 17, 1998, the NCUC granted the Company a Certificate to construct both units. Construction of the combustion turbines began during the first quarter of 1999. Commercial operation is anticipated to begin in June 2000.

On November 17, 1998, the Company made a pre-filing with the NCUC of its plans to construct 1100 MW of combustion turbine generating capacity in Rowan County, North Carolina. On February 17, 1999, the company filed an amendment to its November 17, 1998 pre-filing. The amendment changed the filing in two areas. First, the amount of new combustion turbine generating capacity to be built was increased to 1,600 MW, and second, the site location was changed to a new site in Rowan County and a site in Richmond County. The Company anticipates filing the actual Application for a Certificate of Public Convenience and Necessity with the NCUC on or about March 19, 1999.

INTERCONNECTIONS WITH OTHER SYSTEMS

1. ***Interconnections***. The Company's facilities in Asheville and vicinity are integrated into the total system through the facilities of Duke Energy Corporation (Duke) via interconnection agreements that permit transfer of power to and from the Asheville area. The Company also has major interconnections with the Tennessee Valley Authority (TVA), Appalachian Power Company (APCO), Virginia Power, South Carolina Electric and Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA) and Yadkin, Inc. (Yadkin).

2. ***Interchange and Power Purchase/Sale Agreements***.

   a) The Company has interchange agreements with APCO, Duke, SCE&G, SCPSA, TVA, Virginia Power and Yadkin which provide for the purchase and sale of power for hourly, daily, weekly, monthly or longer periods. In addition to the interchange agreements, the Company has executed individual purchase agreements and sales agreements with more than 100 companies beyond the Virginia-Carolinas Subregion described in paragraph 2.b. below. Purchases and sales under these agreements may be made due to economic or reliability considerations.

      By letter dated May 24, 1996, the Company provided Duke with written notice that effective June 1999, it will terminate Schedule G to the Interchange Agreement between the Company and Duke. Schedule G provides for the wheeling of electricity between the Company's eastern area and its western area.

      By letter dated December 30, 1996, Duke provided the Company with written notice that effective December 31, 1999, it will terminate the Standby Concurrent Exchange Agreement (Standby Agreement) between the Company and Duke. The Standby Agreement provides for the simultaneous exchange of up to 70 MW of electricity during periods of scheduled maintenance or breakdown.

      On December 31, 1996, pursuant to the Federal Energy Regulatory Commission (FERC) Order 888, which directs that no bundled economy energy coordination transactions occur after December 31, 1996, the Company submitted to the FERC a compliance filing to unbundle transmission charges from rate schedules that are applicable to the power sales agreements between the Company and others. See PART I, ITEM 1, "Competition", paragraph 2, for further discussion of the FERC Order 888.

   b) The Virginia-Carolinas Subregion of the Southeastern Electric Reliability Council is principally made up of the Company, Duke, Nantahala Power & Light Company, SCE&G, SCPSA, Virginia Power, Southeastern Power Administration and Yadkin. Electric service reliability is promoted by arrangements among the members of electric reliability organizations at the subregional level.

3. ***Long-Term Purchase Power Contracts***.

   a) In March 1987, the Company entered into an agreement with Duke, which has been accepted by the FERC, whereby Duke would provide 400 MW of firm capacity to the Company's system over the period January 1, 1992, through December 31, 1997. Pursuant to an amendment of the contract, commencement of the purchase of power by the Company was delayed until July 1993 and termination was extended through June 1999. The estimated minimum annual payment for power purchases under the six-year agreement is approximately $48 million, representing capital-related

capacity costs. Purchases under this agreement, including transmission use charges, totaled $75.5 million in 1998.

b) The Company has entered into an agreement, which has been approved by the FERC, with APCO and Indiana Michigan Power Company (Indiana Michigan), operating subsidiaries of American Electric Power Company, to upgrade transmission interconnections in the Company's western and eastern service areas and purchase 250 MW of generating capacity from Indiana Michigan's Rockport Unit No. 2 through 2009. Upgrades to the transmission interconnections in the Company's western and eastern service area were completed in 1992 and 1998, respectively. The estimated minimum annual payment for power purchases under the agreement is approximately $31 million, representing capital-related capacity costs. In 1998, purchases under this agreement, including transmission use charges, totaled $59.3 million.

c) In 1996, the Company agreed with Cogentrix of North Carolina, Inc. and Cogentrix Eastern Carolina Corporation (collectively referred to as Cogentrix) to amend electric power purchase agreements related to five plants owned by Cogentrix. The amendments, which became effective on September 26, 1996, permit the Company to dispatch the output of the five plants. In return, the Company gave up its right to purchase two of the five plants in 1997. As a result of the amendments, the Company expects to realize energy cost savings through the expiration of the agreement in 2002.

d) In December 1998, the Company entered into an agreement to purchase all of the output of a combustion turbine project to be built, owned, and operated by Broad River Energy, LLC, in Cherokee County, South Carolina. The project is scheduled to be in service on or before June 1, 2001 and is expected to have a net dependable capacity of approximately 500 MWs. The agreement is for an initial period of 15 years, with an option for the Company to extend the agreement for two additional five year terms. During the term of the agreement, the Company will have full rights to the output of the project as well as control over the scheduling of the units.

4. *Power Agency*. Pursuant to the terms of a 1981 Power Coordination Agreement, as amended, between the Company and Power Agency, the Company is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant through 2007. A similar buyback arrangement related to the Mayo Plant ended in 1997. The estimated minimum annual payments for these purchases, which reflect capital-related capacity costs, total approximately $26 million. Purchases under the agreement with Power Agency totaled $34.4 million in 1998.

COMPETITION

1. *General.* In recent years, the electric utility industry has experienced a substantial increase in competition at the wholesale level, caused by changes in federal law and regulatory policy. Several states have also decided to restructure aspects of retail electric service. The issue of retail restructuring and competition is being reviewed by a number of states and bills have been introduced in Congress that seek to introduce such restructuring in all states.

Allowing increased competition in the generation and sale of electric power will require resolution of many complex issues. One of the major issues to be resolved is who will pay for stranded costs. Stranded costs are those costs and investments made by utilities in order to meet their statutory obligation to provide electric service, but which could not be recovered through the market price for electricity following industry restructuring. The amount of such stranded costs that the Company might experience would depend on the timing of, and the extent to which, direct competition is introduced, and the then-existing market price of energy. If electric utilities were no longer subject to cost-based regulation and it were not

possible to recover stranded costs, the financial position and results of operations of the Company could be adversely affected.

2. ***Wholesale Competition.*** Since passage of the National Energy Act of 1992 (Energy Act), competition in the wholesale electric utility industry has significantly increased due to a greater participation by traditional electricity suppliers, wholesale power marketers and brokers, and due to the trading of energy futures contracts on various commodities exchanges. This increased competition could affect the Company's load forecasts, plans for power supply and wholesale energy sales and related revenues. The impact could vary depending on the extent to which additional generation is built to compete in the wholesale market, new opportunities are created for the Company to expand its wholesale load, or current wholesale customers elect to purchase from other suppliers after existing contracts expire.

To assist in the development of wholesale competition, the Federal Energy Regulatory commission (FERC), in 1996, issued standards for wholesale wheeling of electric power through its rules on open access transmission and stranded costs and on information systems and standards of conduct (Orders 888 and 889). The rules require all transmitting utilities to have on file an open access transmission tariff, which contains provisions for the recovery of stranded costs and numerous other provisions that could affect the sale of electric energy at the wholesale level. The Company filed its open access transmission tariff with the FERC in mid-1996. Shortly thereafter, Power Agency and other entities filed protests challenging numerous aspects of the Company's tariff and requesting that an evidentiary proceeding be held. The FERC set the matter for hearing and set a discovery and procedural schedule. In July 1997, the Company filed an offer of settlement in this matter. The administrative law judge certified the offer to the full FERC in September 1997. The offer is pending before the FERC. The Company cannot predict the outcome of this matter.

In November 1997, the Company applied to the FERC for authority to sell power at market-based rates. In January 1998, the FERC issued an order accepting the Company's application and permitting the Company to sell power at market-based rates. Excluding sales under specific long-term wholesale agreements, the Company makes virtually all of its wholesale power sales under its market-based rate tariff.

During the last week of June 1998, some wholesale power markets experienced sharp increases in prices. That upsurge in power costs was due, in part, to the unavailability of generating capacity and unusually hot weather in the Midwestern portion of the country. The relatively sudden movement in wholesale power prices disrupted certain power transactions, including some to which the Company was a party. The monetary damages the Company incurred as a result of those disrupted transactions did not have a material adverse effect on the Company's financial position and results of operations. The Company has taken steps to mitigate those monetary damages. The Company anticipates increased volatility in the wholesale power market during peak demand periods; however, due to the risk management processes the Company has in place, the Company does not expect this volatility to have a material adverse effect on its financial position and results of operations.

3. ***Retail Competition.*** The Energy Act prohibits the FERC from ordering retail wheeling - transmitting power on behalf of another producer to an individual retail customer. Several states have changed their laws and regulations to allow full retail competition. Other states are considering changes to allow retail competition. These changes and proposals have taken differing forms and included disparate elements. The Company believes changes in existing laws in both North and South Carolina would be required to permit competition in the Company's retail jurisdictions.

4. ***North Carolina Activities.*** Since 1995, the NCUC has been considering the impact of increased competition in the electric utility industry. In May 1996, the NCUC issued an order stating that the FERC Orders 888 and 889 would provide a new focus for NCUC proceedings with respect to competition in the electric industry. As a result, the NCUC held Docket No. E-100, Sub 77, which concerned retail competition, in abeyance pending further order and established a new docket (Docket No. E-100, Sub 78)

to address the FERC Orders 888 and 889. The NCUC has received several rounds of comments in this docket; the Company filed its most recent comments and reply comments in November 1997 and December 1997, respectively. By order issued June 18, 1998, the Commission held that this docket would also be held in abeyance pending further order. The Company cannot predict the outcome of this matter.

In April 1997, the North Carolina General Assembly (General Assembly) approved legislation establishing a 23-member study commission to evaluate the future of electric service in the state. During 1998, the study commission met and held public hearings around the state. The commission also retained consultants to conduct analyses and studies concerning various restructuring issues, including stranded costs, state and local tax implications and electric rate comparisons. In June 1998, the study commission issued an interim report to the 1998 General Assembly, summarizing the numerous fact-finding and educational activities and analytical projects the commission had initiated or completed. That report offered no judgments or recommendations. The commission is scheduled to make its final report to the 1999 Session of the General Assembly which will begin in 1999 and continue during 2000. The Company cannot predict the outcome of this matter.

5. ***South Carolina Activities.*** The South Carolina General Assembly ended its 1998 session without enacting any legislation regarding electric restructuring. On October 29, 1998, the South Carolina Senate Judiciary Committee appointed a 13-member task force to study the restructuring issue and make a report to the South Carolina General Assembly during the 1999 legislative session. The task force was subsequently expanded to 18 members, including the Company. The General Assembly's House Utility Subcommittee is also expected to continue pursuing the issue during that session. The Company cannot predict the outcome of these matters.

6. ***Federal Activities.*** At the federal level, additional bills regarding restructuring of the electric utility industry were introduced in 1998, but Congress adjourned in October without taking any action on the issue. The debate regarding industry restructuring is expected to continue in Congress in 1999. The Company cannot predict the outcome of this matter.

7. ***Company Activities.*** The developments described above have created changing markets for energy. As a strategy for competing in these changing markets, the Company is becoming a total energy provider in the region by providing a full array of energy-related services to its current customers and expanding its market reach. As part of this strategy, the Company plans to position itself as a supplier of natural gas to its customers. The Company took a major step towards reaching this goal on November 10, 1998 by entering into the Merger Agreement with North Carolina Natural Gas Corporation (NCNG).

On March 3, 1999, the Company and Southern Natural Gas Co., a subsidiary of Sonat Inc., announced plans to form a 50/50 joint venture to construct, own and operate a 175 mile, 30-inch natural gas pipeline from Aiken, South Carolina to an interconnect with the NCNG system in Robeson County, North Carolina. The new Palmetto Interstate Pipeline will have a capacity of 200 million to 300 million cubic feet per day and will be expandable to accommodate future growth and demand along its route. Most of the pipeline's capacity will be used by the Company to fuel new electric generation it will develop in the Carolinas over the next several years. The remaining pipeline capacity will be used to increase the region's natural gas availability. Construction of the new pipeline will begin after engineering, environmental preparation and federal and state permitting are completed. The current schedule calls for construction to begin mid-2001, with the pipeline to be operational in April 2002. The pipeline's cost is expected to be $200 million to $250 million.

The Company currently plans to construct approximately 2300 MW of new generating facilities by the year 2002. These facilities, including two combustion turbine facilities outside of the Company's current service area, will help the Company continue to meet the needs of its growing retail customer base and increase its ability to participate in the wholesale energy supply business.

The Company's strategy for addressing the planning uncertainty and risks created by the changing markets for energy includes securing long-term contracts with its wholesale customers, continuing to work to meet the energy needs of its industrial customers, promoting economic development, implementing new marketing strategies, improving customer satisfaction, and increasing the focus on managing and reducing costs and, consequently, avoiding future rate increases.

In 1996, Power Agency notified the Company that it would discontinue certain contractual purchases of power from the Company effective September 1, 2001; however, the Company won the right to continue supplying this power by being selected from a number of bidders. On September 11, 1998, the Company and Power Agency entered into a revised agreement that extends the period during which Power Agency will continue to purchase all of its supplemental power from the Company through at least December 31, 2002. The new agreement also includes options for Power Agency to purchase supplemental power from the Company for the year 2003 and beyond. The load served by supplemental power under that agreement will include all of Power Agency's power needs in excess of the load served by Power Agency through its ownership interest in generation units that it jointly owns with the Company and other smaller resources that are currently in place. The revised agreement was filed with, and has been accepted by, the FERC.

On October 9, 1998, the Company and its largest customer, NCEMC, entered into an agreement under which NCEMC will purchase a total of 800 MWs of peaking capacity and associated energy from the Company during the period from January 1, 2001 through December 31, 2003. The agreement, which provides NCEMC with an option to extend all or part of the purchase through 2005, provides capacity to meet NCEMC's growing peaking power needs. A portion of this purchase is intended to serve load located in the Company's service area that is currently served by purchases from the Company under a contract that will expire on December 31, 2000. During the period 2001 through 2003, this agreement also will serve up to 450 MWs of NCEMC load that is located in the Duke Power service area that has not previously been served by the Company. The agreement will be filed with the FERC for approval or acceptance. The Company cannot predict the outcome of this matter.

On October 30, 1998, the Company and NCEMC also entered into agreements that supersede the 1993 Power Coordination Agreement between the Company and NCEMC, as amended (the PCA). The primary effect of the new agreements is to unbundle the generation and transmission service for the load previously served under the PCA. To that end, the parties executed a Network Integration Transmission Service Agreement and a Network Operating Agreement under which NCEMC will receive transmission services from the Company pursuant to the Company's Open Access Transmission Tariff. The parties also entered into a new Power Supply Agreement , which provides for the Company to sell capacity and energy to NCEMC under terms and conditions and in amounts that are substantially the same as those that were set forth in the PCA. The parties agreed to a modification of the calculation of certain capacity charges; however, the net effect of the changes is intended to be essentially revenue neutral under expected load conditions. The Network Integration Transmission Service Agreement, the Network Operating Agreement and the new Power Supply Agreement were filed with FERC on November 3, 1998 and have been accepted. The new Power Supply Agreement has also been submitted by NCEMC to the Rural Utilities Service for approval. The Company cannot predict the outcome of this matter.

On September 28, 1998, the Company and the South Carolina Public Service Authority (Santee Cooper) entered into an agreement under which the Company will provide peaking capacity and associated energy to Santee Cooper for the period January 1, 1999 through December 31, 2003. Under the terms of the agreement, the Company will provide 100 MW of generation capacity in 1999, 150 MW in 2000 and 200 MW from 2001 to 2003. The agreement was filed with, and has been accepted by, the FERC.

As a regulated entity, the Company is subject to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," (SFAS-71). Accordingly, the Company records certain assets and liabilities resulting from the effects of the ratemaking process, which would not be recorded under generally accepted accounting principles for unregulated entities. The

Company's ability to continue to meet the criteria for application of SFAS-71 may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS-71 no longer applied to a separable portion of the Company's operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment of electric utility plant assets as determined pursuant to Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of."

CAPITAL REQUIREMENTS

Capital Requirements. During 1998 the Company expended approximately $725 million for capital requirements. Estimated capital requirements for 1999 through 2001 primarily reflect construction expenditures to add generation, transmission and distribution facilities, as well as upgrade existing facilities. Those capital requirements are reflected in the following table (in millions):

	1999	2000	2001
Construction Expenditures	$649	$860	$1,104
Nuclear Fuel Expenditures	77	93	64
AFUDC	(17)	(29)	(54)
Mandatory Retirements of Long-Term Debt	53	198	-
TOTAL	$762	$1,122	$1,114

This table includes environmental expenditures relating to the Clean Air Act of approximately $27 million, and the NOx SIP Call of approximately $195 million. See PART I, ITEM 1, "Environmental Matters", paragraph 2, and "Generating Capability", paragraph 3, for further discussion of the impact of the Clean Air Act and NOx SIP Call on the Company, and planned generation additions, respectively.

In addition, the Company has total projected cash requirements of approximately $356 million for the years 1999 through 2001 relating to expenditures in other areas such as affordable housing investments and telecommunications infrastructure development. These projections are periodically reviewed and may change significantly.

FINANCING REQUIREMENTS

1. ***Financing Requirements***. The proceeds from the issuance of commercial paper related to the credit facilities mentioned below (see paragraph 5 below) and/or internally generated funds financed the retirement of long-term debt totaling $205 million in 1998. External funding requirements, which do not include early redemptions of long-term debt or redemptions of preferred stock, are expected to approximate $375 million, $500 million and $460 million in 1999, 2000 and 2001, respectively. These funds will be required for construction, mandatory retirements of long-term debt and general corporate purposes. The amount and timing of future sales of Company securities will depend upon market conditions and the specific needs of the Company. The Company may from time to time sell securities beyond the amount needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes. See PART II, 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.

2. *SEC Filings*.

i) The Company has on file with the Securities and Exchange Commission (SEC) a shelf registration statement (File No. 333-69237) under which $1.5 billion aggregate principal amount of first mortgage bonds, senior notes and other debt securities are available for issuance by the Company.

ii) The Company has on file with the SEC a shelf registration statement (File No. 33-5134) enabling the Company to issue up to $180 million of Serial Preferred Stock.

3. *Issuances of Bonds, Preferred Stock and Debentures*.

External financings during 1998 and early 1999 included:

The issuance on March 5, 1999 of $400 million principal amount of Senior Notes, 5.95% Series due on March 1, 2009. The net proceeds of approximately $390 million were used to reduce the outstanding balance of commercial paper and for other general corporate purposes.

4. *Redemptions/Retirements of Bonds, Preferred Stock and Debentures*.

Redemptions and retirements during 1998 included:

i) The redemption on June 1, 1998, of $40 million principal amount of First Mortgage Bonds, 6-7/8% Series due October 1, 1998.

ii) The retirement on July 1, 1998, of $100 million principal amount of First Mortgage Bonds, 5-3/8% Series, which matured on that date.

iii) The retirement on September 13, 1998, of $5 million principal amount of First Mortgage Bonds, Secured Medium-Term Notes, 5.05% Series C, which matured on that date.

iv) The retirement on September 13, 1998, of $5 million principal amount of First Mortgage Bonds, Secured Medium-Term Notes, 5.06% Series C, which matured on that date.

v) The retirement on September 15, 1998, of $20 million principal amount of First Mortgage Bonds, Secured Medium-Term Notes, 5.00% Series C, which matured on that date.

vi) The retirement on September 15, 1998, of $15 million principal amount of First Mortgage Bonds, Secured Medium-Term Notes, 5.01% Series C, which matured on that date.

vii) The retirement on October 19, 1998, of $20 million principal amount of First Mortgage Bonds, Secured Medium-Term Notes, 5.00% Series C, which matured on that date.

5. *Credit Facilities*. As of December 31, 1998, the Company's revolving credit facilities totaled $750 million, all of which are long-term agreements supporting its commercial paper borrowings. The Company is

required to pay minimal annual commitment fees to maintain its credit facilities. Consistent with management's intent to maintain its commercial paper on a long-term basis, and as supported by its long-term revolving credit facilities, the Company included in its long-term debt all commercial paper outstanding as of December 31, 1998 which amounted to $488 million. See PART II, ITEM 8, "CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA", Note 4, for a more detailed discussion of the Company's revolving credit facilities.

RETAIL RATE MATTERS

1. ***General***. The Company is subject to regulation in North Carolina by the NCUC and in South Carolina by the South Carolina Public Service Commission (SCPSC) with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities.

2. ***Current Retail Rates***. The rates of return granted to the Company in its most recent general rate cases are as follows:

1988 North Carolina Utilities Commission Order (test year ended March 31, 1987)

Capital Structure	Capital Ratio	Weighted Cost Rate	Weighted Cost
Long-Term Debt	48.57%	8.62%	4.19%
Preferred Stock	7.43	8.75	.65
Common Equity	44.00	12.75	5.61
Rate of Return			10.45%

1988 South Carolina Public Service Commission Order (test year ended September 30, 1987)

Capital Structure	Capital Ratio	Weighted Cost Rate	Weighted Cost
Long-Term Debt	47.82%	8.62%	4.12%
Preferred Stock	7.46	8.75	.65
Common Equity	44.72	12.75	5.71
Rate of Return			10.48%

3. ***Other Retail Rate Matters.*** A petition was filed in July 1996 by the Carolina Industrial Group for Fair Utility Rates (CIGFUR) with the NCUC, requesting that the NCUC conduct an investigation of the Company's base rates or treat its petition as a complaint against the Company. The petition alleged that the Company's return on equity (which was authorized by the NCUC in the Company's last general rate proceeding in 1988) and earnings are too high. In December 1996, the NCUC issued an order denying CIGFUR's petition and stating that it tentatively found no reasonable grounds to proceed with CIGFUR's petition as a complaint. Subsequently, CIGFUR filed a Motion for Reconsideration with the NCUC and a Notice of Appeal with the North Carolina Court of Appeals, both of which were denied. On December 4, 1998, a petition for Discretionary Review filed by CIGFUR was denied by the North Carolina Supreme Court.

Pursuant to authorizations from the NCUC and the SCPSC, the Company began to accelerate the

amortization of certain regulatory assets over a three-year period beginning January 1997. The accelerated amortization of these regulatory assets results in additional depreciation and amortization expenses of approximately $68 million in each year of the three-year period.

In 1996, the NCUC also authorized the Company to defer operation and maintenance expenses of approximately $40 million associated with Hurricane Fran, with amortization over a 40-month period.

In late 1998 and early 1999, the Company filed, and the respective commissions subsequently approved, proposals in the North and South Carolina retail jurisdictions to accelerate cost recovery of its nuclear generating assets beginning January 1, 2000 and continuing through 2004. The accelerated cost recovery begins immediately after the 1999 expiration of the accelerated amortization of certain regulatory assets, which began in January 1997. Pursuant to the orders, the Company's depreciation expense for nuclear generating assets will increase by $106 million to $150 million per year. Recovering the costs of the nuclear generating assets on an accelerated basis will better position the Company for the uncertainties associated with potential restructuring of the electric utility industry.

4. ***Integrated Resource Planning.*** Integrated resource planning is a process that systematically compares all reasonably available resources, both demand-side and supply-side, in order to develop that mix of resources that allows a utility to meet customer demand in a cost-effective manner, giving due regard to system reliability, safety and the environment. In the past, utilities were required to file their Integrated Resource Plans (IRP) with the NCUC and the SCPSC once every three years. The Company regularly reviews its IRP in light of changing conditions and evaluates the impact these changes have on its resource plans, including purchases and other resource options. During 1998, the NCUC and SCPSC substantially altered their IRP rules. Both the NCUC and SCPSC reduced the amount of information that must be included in the Company's IRP. The NCUC also eliminated the triennial IRP and now requires an annual filing.

5. ***Fuel Cost Recovery.***

    a) In the North Carolina retail jurisdiction, the NCUC establishes base fuel costs in general rate cases and holds hearings annually 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 as well as changes in the fuel cost component of sales to other utilities. The NCUC considers the changes in the Company's cost of fuel during a historic test period ending March 31 of each year and corrects any past over- or under-recovery. On June 4, 1998, the Company filed its 1998 fuel cost recovery application. The NCUC issued a final order approving the Company's proposed billing fuel factor of 1.079 cents/kWh on September 9, 1998. This new factor became effective on September 15, 1998.

    b) In the South Carolina retail jurisdiction, fuel rates are set by the SCPSC. At the fuel hearings, any past over- or under-recovery of fuel costs is taken into account in establishing the new rate. On February 22, 1999, the Company filed a proposal with the SCPSC to continue the existing fuel factor of 1.122 cents/kWh. The Company's 1999 fuel hearing was held on March 24, 1999.

6. ***Avoided Cost Proceedings.*** In 1998, the NCUC opened Docket No. E-100, Sub 81 for its biennial proceeding to establish the avoided cost rates for all electric utilities in North Carolina. Avoided cost rates are intended to reflect the costs that utilities are able to "avoid" by purchasing power from qualifying facilities. The Company's initial filing in this docket was made on November 6, 1998. Intervenor

comments on the utilities' filings were filed January 15, 1999, and a hearing for non-expert public witnesses was held on February 2, 1999. The Company cannot predict the outcome of this matter.

WHOLESALE RATE MATTERS.

The Company is subject to regulation by the FERC with respect to rates for transmission and sale of electric energy at wholesale, the interconnection of facilities in interstate commerce (other than interconnections for use in the event of certain emergency situations), the licensing and operation of hydroelectric projects and, to the extent the FERC determines, accounting policies and practices. The Company and its wholesale customers last agreed to a general increase in wholesale rates in 1988; however, wholesale rates have been adjusted since that time through contractual negotiations.

ENVIRONMENTAL MATTERS

1. ***General***. In the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes and other environmental matters, the Company is subject to regulation by various federal, state and local authorities. The Company considers itself to be in substantial compliance with those environmental regulations currently applicable to its business and operations and believes it has all necessary permits to conduct such operations. Environmental laws and regulations constantly evolve and the ultimate costs of compliance cannot always be accurately estimated. The costs associated with compliance with pollution control laws and regulations at the Company's existing facilities that the Company expects to incur from 1999 through 2001 are included in the estimates of capital requirements under PART I, ITEM 1, "Capital Requirements".

2. ***Clean Air Legislation***. The 1990 amendments to the Clean Air Act (Act) require substantial reductions in sulfur dioxide and nitrogen oxides emissions from fossil-fueled electric generating plants. The Act will require the Company to meet more stringent provisions effective January 1, 2000. The Company plans to meet the sulfur dioxide emissions requirements by utilizing the most economical combination of fuel-switching and sulfur dioxide emission allowances. Installation of additional equipment will be necessary to reduce nitrogen oxide emissions. The Company estimates that future capital expenditures necessary to meet the nitrogen oxide emission requirements will approximate $27 million. Increased operation and maintenance costs, including emission allowance expenses and increased fuel costs are not expected to be material to the Company's results of operations.

   On October 27, 1998, the Environmental Protection Agency (EPA) published a final rule addressing the issue of regional transport of ozone. This rule is commonly known as the NOx SIP call. The EPA's rule requires 22 states, including North and South Carolina, to further reduce nitrogen oxide emission in order to attain a pre-set state NOx emission level by May 2003. The EPA's rule also suggests to the states that these additional nitrogen oxide emission reductions be obtained from the utility sector. The Company is evaluating necessary measures to comply with the rule and estimates its related capital expenditures through 2003 could be approximately $327 million. Increased operation and maintenance costs relating to the NOx SIP call are not expected to be material to the Company's results of operations. The Company and the states of North and South Carolina are participating in litigation challenging the NOx SIP call. The Company cannot predict the outcome of this matter.

   With regard to revisions to existing air quality standards, in July 1997 the EPA issued final regulations establishing a new fine-particulate standard. These regulations may require the installation of additional control equipment at some of the Company's fossil-fueled electric generating plants. The Company is evaluating the effects of these and other similar regulations and cannot determine the estimated costs

that may be required for compliance. The Company cannot predict the outcome of this matter.

3. ***Superfund***. The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require clean up of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North and South Carolina, have similar types of legislation. There are presently several sites with respect to which the Company has been notified by the EPA or the State of North Carolina of its potential liability, as described below in greater detail.

   Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under various federal and state laws. There are several manufactured gas plant (MGP) sites to which the Company and certain entities that were later merged into the Company had some connection. In this regard, the Company, along with others, is participating in a cooperative effort with the North Carolina Department of Environment and Natural Resources, Division of Waste Management (DWM), which has established a uniform framework to address MGP sites. The investigation and remediation of specific MGP sites will be addressed pursuant to one or more Administrative Orders on Consent (AOC) between the DWM and the potentially responsible party or parties. The Company has signed AOCs to investigate certain sites. The Company continues to investigate the identities of parties connected to individual MGP sites, the relative relationships of the Company and other parties to those sites and the degree to which the Company will undertake efforts with others at individual sites. The Company does not expect the costs associated with these sites to be material to the financial position and results of operations of the Company.

   The Company has been notified by regulators of its involvement or potential involvement in several sites, other than MGP sites, that may require investigation and/or remediation. Although the Company may incur costs at these sites, the investigation and/or remediation of the sites has not advanced to a stage where reasonable cost estimates can be made. The Company cannot predict the outcome of these matters.

4. ***Other Environmental Matters***. The Company has filed claims with its general liability insurance carriers to recover costs arising out of actual or potential environmental liabilities. Some claims have been settled, and others are still being pursued. The Company cannot predict the outcome of these matters.

5. ***Environmental Accrual***. The Company carries a liability for the estimated costs associated with certain remedial activities. This liability is not material to the financial position of the Company.

NUCLEAR MATTERS

1. ***General***. Under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974, as amended, operation of nuclear plants is intensively regulated by the Nuclear Regulatory Commission (NRC), which has broad power to impose nuclear safety and security requirements. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, or shut down a nuclear unit, or some combination of these, depending upon its assessment of the severity of the situation, until compliance is achieved. The electric utility industry in general has experienced challenges in a number of areas relating to the operation of nuclear plants, including: substantially increased capital outlays for modifications; the effects of inflation upon the cost of operations; increased costs related to compliance with changing regulatory requirements; renewed emphasis on achieving excellence in all phases of operations; unscheduled outages; outage durations; and uncertainties regarding disposal facilities for low-level radioactive waste and storage facilities for spent nuclear fuel. See paragraphs 2 and 3 below. The

Company experiences these challenges to varying degrees. Capital expenditures for modifications at the Company's nuclear units, excluding Power Agency's ownership interests, during 1999, 2000 and 2001 are expected to total approximately $54 million, $35 million, and $73 million, respectively (including AFUDC).

2. ***Spent Fuel and Other High-Level Radioactive Waste***. The Nuclear Waste Policy Act of 1982 (Nuclear Waste Act) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The Nuclear Waste Act promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. The Company will continue to maximize the use of spent fuel storage capability within its own facilities for as long as feasible. As of December 31, 1998, sufficient on-site spent nuclear fuel storage capability is available for the full-core discharge of Brunswick Unit No. 1 through 1999, Brunswick Unit No. 2 through 2000, Robinson Unit No. 2 through 2000 and Harris through 2002 assuming normal operating and refueling schedules. The spent fuel storage facilities at the Brunswick and Robinson Units along with the Harris Plant spent fuel storage facilities are sufficient to provide storage space for spent fuel generated by all of the Company's nuclear generating units through the expiration of their current operating licenses, provided that currently idle storage space at the Harris Plant can be activated. On December 23, 1998, the Company submitted a license amendment application to the NRC requesting approval to activate and begin using the additional spent fuel storage at the Harris Plant. The Company is maintaining full-core discharge capability for the Brunswick Units and Robinson Unit No. 2 by transferring spent nuclear fuel by rail to the Harris Plant. As a contingency to the shipment by rail of spent nuclear fuel, during April 1989, the Company filed an application with the NRC for the issuance of a license to construct and operate an independent spent fuel storage facility for the dry storage of spent nuclear fuel at the Brunswick Plant. At the Company's request, the NRC suspended review of the Company's license application based on the success of the Company's shipping efforts. The NRC will resume review of the license upon notification by the Company of its desire to continue the application process. Subsequent to the expiration of the licenses, dry storage may be necessary in conjunction with the decommissioning of the units. Pursuant to the Nuclear Waste Act, the Company, through a joint agreement with the U. S. Department of Energy (DOE) and the Electric Power Research Institute, has built a demonstration facility at the Robinson Plant that allows for the dry storage of 56 spent nuclear fuel assemblies. The Company cannot predict the outcome of these matters.

As required under the Nuclear Waste Policy Act of 1982, the Company entered into a contract with the DOE under which the DOE agreed to begin taking spent nuclear fuel by January 31, 1998. The DOE defaulted on its January 31, 1998 obligation to begin taking spent nuclear fuel, and a group of utilities, including the Company, has undertaken measures to force the DOE to take spent nuclear fuel. To date, the courts have rejected these attempts. In addition, several utilities have filed actions for damages in the United States Court of Claims, and in some of those cases the Court has agreed that the DOE has breached its contract for disposal of spent nuclear fuel. The Company is in the process of evaluating whether it should file a similar action for damages. The Company will also monitor legislation that has been introduced in Congress that would provide for interim storage of spent nuclear fuel at a storage facility operated by the DOE. The Company cannot predict the outcome of this matter.

3. ***Low-Level Radioactive Waste***. Disposal costs for low-level radioactive waste that result from normal operation of nuclear units have increased significantly in recent years and are expected to continue to rise. Pursuant to the Low-Level Radioactive Waste Policy Act of 1980, as amended in 1985, each state is responsible for disposal of low-level waste generated in that state. States that do not have existing sites may join in regional compacts. The States of North and South Carolina were participants in the Southeast

Regional Compact and disposed of waste at a disposal site in South Carolina along with other members of the compact. Effective July 1, 1995, South Carolina withdrew from the Southeast regional compact and excluded North Carolina waste generators from the existing disposal site in South Carolina. As a result, the State of North Carolina does not have access to a low-level radioactive waste disposal facility. The North Carolina Low-Level Radioactive Waste Management Authority, which is responsible for siting and operating a new low-level radioactive waste disposal facility for the Southeast regional compact, has submitted a license application for the site it selected in Wake County, North Carolina to the North Carolina Division of Radiation Protection. In December 1997, the Southeast Regional Compact Commission suspended funding for the proposed low-level radioactive waste facility in Wake County. The future funding for this project remains uncertain. Although the Company does not control the future availability of low-level waste disposal facilities, the cost of waste disposal or the development process, it supports the development of new facilities and is committed to a timely and cost-effective solution to low-level waste disposal. The Company's nuclear plants in North Carolina are currently storing low-level waste on site and are developing additional storage capacity to accommodate future needs. The Company's nuclear plant in South Carolina has access to the existing disposal site in South Carolina. Although the Company cannot predict the outcome of this matter, it does not expect the cost of providing additional on-site storage capacity for low-level radioactive waste to be material to the results of operations or financial position of the Company.

4. ***Decommissioning*.**

a) Pursuant to an NRC rule, licensees of nuclear facilities are required to submit decommissioning funding plans to the NRC for approval to provide reasonable assurance that the licensee will have the financial ability to implement its decommissioning plan for each facility. The rule requires licensees to do one of the following: prepay at least an NRC-prescribed minimum amount immediately; set up an external sinking fund for accumulation of at least that minimum amount over the operating life of the facility; or provide a surety to guarantee financial performance in the event of the licensee's financial inability to perform actual decommissioning. On July 26, 1990, the Company submitted its decommissioning funding plans to the NRC. In this regard, the Company entered into a Master Decommissioning Trust Agreement dated July 19, 1990 (Trust), with Wachovia Bank of North Carolina, N.A., as Trustee, as a vehicle to achieve such decommissioning funding. In June 1991, the Company began depositing funds into the Trust.

In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC and the SCPSC and are based on site-specific estimates that included the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdiction, the provisions for nuclear decommissioning costs are based on amounts agreed upon in applicable rate agreements. Decommissioning cost provisions, which are included in depreciation and amortization expense, were $33.3 million, $33.2 million and $33.1 million in 1998, 1997 and 1996, respectively. Accumulated decommissioning costs, which are included in accumulated depreciation, were $496.3 million and $428.7 million at December 31, 1998 and 1997, respectively. These costs include amounts retained internally and amounts funded in an external decommissioning trust. The balance of the nuclear decommissioning trust was $310.7 million and $245.5 million at December 31, 1998 and 1997, respectively. Trust earnings increase the trust balance with a corresponding increase in the accumulated decommissioning balance. These balances are adjusted for net unrealized gains and losses related to changes in the fair value of trust assets. Based on the site-specific estimates discussed below, and using an assumed after-tax earnings rate of 7.75% and an assumed cost escalation rate of 4%, current levels of rate recovery

for nuclear decommissioning costs are adequate to provide for decommissioning of the Company's nuclear facilities.

b) The Company's most recent site-specific estimates of decommissioning costs were developed in 1998, using 1998 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring shortly after operating license expiration. See paragraph 5 below for expiration dates of operating licenses. These estimates, in 1998 dollars, are $279.8 million for Robinson Unit No. 2, $299.3 million for Brunswick Unit No. 1, $298.5 million for Brunswick Unit No. 2, and $328.1 million for the Harris Plant. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to Power Agency, which holds an undivided ownership interest in the Brunswick and Harris nuclear generating facilities. To the extent of its ownership interests, Power Agency is responsible for satisfying the NRC's financial assurance requirements for decommissioning costs. See PART I, ITEM 1, "Generating Capabilities", paragraph 1.

c) The Financial Accounting Standards Board is proceeding with its project regarding accounting practices related to obligations associated with the retirement of long-lived assets, and an exposure draft of a proposed accounting standard is expected to be issued during the first half of 1999. It is uncertain when a final statement will be issued and what effects it may ultimately have on the Company's accounting for nuclear decommissioning and other retirement costs.

5. ***Operating Licenses***. Facility Operating Licenses, issued by the NRC, for the Company's nuclear units allow for a full 40 years of operation. Expiration dates for these licenses are set forth in the following table.

Facility	Facility Operating License Expiration Date
Robinson Unit No. 2	July 31, 2010
Brunswick Unit No. 1	September 8, 2016
Brunswick Unit No. 2	December 27, 2014
Harris Plant	October 24, 2026

6. ***Other Nuclear Matters***

a) In 1991, the NRC issued a final rule on nuclear plant maintenance that became effective on July 10, 1996. In general terms, the new maintenance rule prescribes the establishment of performance criteria for each safety system based on the significance of that system. The rule also requires monitoring of safety system performance against the established acceptance criteria, and provides that remedial action be taken when performance falls below the established criteria. In March 1998, the Company's Maintenance Rule Program was found acceptable by the NRC during baseline inspections.

b) On November 23, 1988, the NRC requested in Generic Letter 88-20 that utilities perform Individual Plant Examinations (IPEs) to determine potential vulnerabilities to severe accidents beyond the design basis accidents for which the plants are designed. These are considered to be

very low probability events. The Company submitted the results of the first phase (for internally initiated events) in August 1992 for the Brunswick and Robinson Plants. Based on those results, potential enhancements for the Robinson Plant were evaluated and several enhancements were made to the Robinson Plant. These changes had insignificant financial and operational impacts. For the Brunswick Plant, no modifications were required to meet the guidelines of the IPE. On August 20, 1993, the Company submitted the results of the Harris Plant IPE. While some Harris Plant procedural changes were made due to the IPE results, the IPE did not result in any significant financial or operational impacts or identify any need for plant modifications. In June 1995, the Company completed and submitted the results of the second phase of the IPEs (for externally initiated events) for the Company's three nuclear plants. The results of the IPEs indicated some potential procedural changes for the Harris and Brunswick Plants. Those results also indicated that both minor procedural changes and minor plant modifications would be required for the Robinson Plant. All IPE items and findings had been addressed and implemented by the end of 1998.

c) Degradation of tubing internal to steam generators in pressurized water reactor power plants due to intergranular stress corrosion cracking has been an on-going industry phenomenon. The Company has determined that the steam generators at the Harris Plant are subject to degradation and plans to replace the steam generators in 2001. The steam generators at the Robinson plant were replaced in 1984 and are expected to perform until the plant's operating license expires. The Company does not expect the costs associated with replacing the steam generators at the Harris Plant to be material to the financial position of the Company.

d) The Company is insured against public liability for a nuclear incident up to \$9.8 billion per occurrence, which is the maximum limit on public liability claims pursuant to the Price-Anderson Act. In the event that public liability claims from an insured nuclear incident exceed \$200 million, the Company would be subject to a pro rata assessment of up to \$83.9 million, plus a 5% surcharge, for each reactor owned for each incident. Payment of such assessment would be made over time as necessary to limit the payment in any one year to no more than \$10 million per reactor owned. Power Agency would be responsible for its ownership share of the assessment on jointly owned nuclear units. For a more detailed discussion of nuclear liability insurance, see PART II, ITEM 8, "CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA", Note 12 b.

FUEL

1. ***Sources of Generation***. Total system generation (including Power Agency's share) by primary energy source, along with purchased power, for the years 1995 through 1999 is set forth below:

	1995	1996	1997	1998	1999 (estimated)
Fossil	44%	45%	46%	47%	49%
Nuclear	42	41	43	42	41
Purchased Power	13	12	10	9	9
Hydro	1	2	1	1	1
Combustion Turbine	-	-	-	1	-

2. ***Coal***. The Company has intermediate and long-term agreements from which it expects to receive

approximately 90% of its coal burn requirements in 1999. These agreements have expiration dates ranging from 1999 to 2006. All of the coal that the Company is currently purchasing under intermediate and long-term agreements is considered to be low sulfur coal by industry standards. Recent amendments to the Clean Air Act may result in increases in the price of low sulfur coal. See PART I, ITEM 1, "Environmental Matters", paragraph 2. The average cost (including transportation costs) to the Company of coal delivered for 1998 was $41.10 per ton.

3. ***Oil***. The Company uses No. 2 oil primarily for its combustion turbine units, which are used for emergency backup and peaking purposes, and for boiler start-up and flame stabilization. The Company has a No. 2 oil supply contract 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 combustion turbine units, thereby increasing No. 2 oil consumption. The Company intends to meet any additional requirements for No. 2 oil through additional contract purchases or purchases in the spot market. There can be no assurance that adequate supplies of No. 2 oil will be available to meet the Company's requirements. To reduce the Company's vulnerability to the lack of No. 2 oil availability, fourteen combustion turbine units with a total generating capacity of 665 MW can also burn natural gas. Over the last five years, No. 2 oil, natural gas and propane accounted for 2.40% of the Company's total burned fuel cost. In 1998, No. 2 oil, natural gas and propane accounted for 4.03% of the Company's total burned fuel cost. The availability and cost of fuel oil could be adversely affected by energy legislation enacted by Congress, disruption of oil or gas supplies, labor unrest and the production, pricing and embargo policies of foreign countries.

4. ***Nuclear***. The nuclear fuel cycle requires the mining and milling of uranium ore to provide uranium oxide concentrate (U_3O_8), the conversion of U_3O_8 to uranium hexafluoride (UF_6), the enrichment of the UF_6 and the fabrication of the enriched uranium into fuel assemblies. Existing uranium contracts are expected to supply the necessary nuclear fuel to operate all of the Company's nuclear generating facilities through 2001.

The Company expects to meet its future U_3O_8 requirements from inventory on hand and amounts received under contract. Although the Company cannot predict the future availability of uranium and nuclear fuel services, the Company does not currently expect to have difficulty obtaining U_3O_8 and the services necessary for its conversion, enrichment and fabrication into nuclear fuel. For a discussion of the Company's plans with respect to spent fuel storage, see PART I, ITEM 1, "Nuclear Matters", paragraph 2.

5. ***DOE Enrichment Facilities Decontamination and Decommissioning (D&D) Fund***. Under Title XI of the Energy Policy Act of 1992, Public Law 102-486, Congress established a decontamination and decommissioning (D&D) fund for the DOE's gaseous diffusion enrichment plants. Contributions to this fund are being made by U.S. domestic utilities which have purchased enrichment services from DOE since it began sales to non-Department of Defense customers. Each utility's share of the contributions is based on that utility's past purchases of services as a percentage of all purchases of services by U.S. utilities. Total annual contributions are capped at $150 million per year with an overall cap of $2.25 billion over 15 years both indexed to inflation. The Company has paid approximately $34 million in D&D fees through 1998, and expects to pay a cumulative total of approximately $83 million over the 15 year period ending September 30, 2007 (excluding Power Agency's ownership share). The Company is recovering these costs as a component of fuel cost.

During March 1997, the Company, along with other entities, filed an administrative claim with the DOE, and a Complaint against the DOE in the United States Court of Federal Claims, seeking a refund of part of the price paid by the Company for enrichment services purchased from the DOE. It is the Company's position that the contract price it paid to the DOE for uranium purchases included the cost of D&D, and

that the DOE's collection of additional D&D fees pursuant to the Energy Act resulted in an overpayment of fees by the Company. In addition, the claim requested the elimination of future D&D fund assessments. It was the Company's position that the D&D assessments constitute a breach of contract, a taking of vested contract rights, a violation of property rights, illegal exaction and a violation of the Fifth Amendment of the United States Constitution. The Company's action was stayed pending the outcome of a similar case, Yankee Atomic Electric Company (Yankee Atomic) v. United States (33 Fed.Cl. 580 (Cl.Ct. 1995)), in which the United States Court of Claims found that a portion of the D&D assessments made against Yankee Atomic were unlawful. The government appealed that case to the District of Columbia Circuit Court of Appeals, which subsequently overturned the favorable Court of Claims decision. After the Circuit Court of Appeals refused to rehear the matter, Yankee Atomic filed a petition for a certiorari to seek a review by the United States Supreme Court, which was denied. During February 1999, the Company amended its complaint for various reasons, and the government subsequently filed a motion to dismiss. The total refund demanded in the Company's amended complaint through the date of the complaint filing (including Power Agency's ownership share) is approximately $39 million. The Company cannot predict the outcome of this matter.

6. ***Purchased Power***. The Company purchased 5,336,867 MWh in 1998, 5,886,722 MWh in 1997 and 6,792,340 MWh in 1996 or approximately 9%, 10% and 12%, respectively, of its system energy requirements (including Power Agency) and had available 1,438 MW in 1998, 1,839 MW in 1997 and 1,536 MW in 1996 of firm purchased capacity under contract at the time of peak load. The Company may acquire purchased power capacity in the future to accommodate a portion of its system load needs.

NCNG MERGER

On November 10, 1998, the Company and North Carolina Natural Gas Corporation entered into an Agreement and Plan of Merger (Merger Agreement) providing for the strategic business combination of the Company and NCNG. Pursuant to the Merger Agreement, NCNG will become a wholly owned subsidiary of the Company. The Merger is intended to constitute a tax-free reorganization for federal income tax purposes and to be accounted for as a pooling-of-interests. The Company will issue approximately $354 million in stock to NCNG shareholders to complete the merger.

The Merger Agreement has been approved by the Boards of Directors of the Company and NCNG. Consummation of the Merger is subject to certain closing conditions, including approval by the shareholders of NCNG and certain regulatory approvals or filings. Applications for regulatory approval were filed with the NCUC on January 11, 1999, and with the SCPSC on February 9, 1999. NCNG presently intends that the shareholders meeting to consider such approval will be held as early as practicable. The requisite notifications were filed with the Federal Trade Commission and the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, during March 1999.

Further details concerning the proposed transaction are provided in the Company's Form 10-Q for the quarter ended September 30, 1998, which was filed with the SEC on November 13, 1998.

DIVERSIFIED BUSINESSES

1. ***Strategic Resource Solutions Corp.*** Strategic Resource Solutions Corp. (SRS), a wholly owned subsidiary, specializes in facilities and energy management software, systems and services for educational, commercial, industrial and governmental markets nationwide. During 1998, SRS acquired the following companies: Parke Industries Inc., a lighting retrofit company located in California; Intelligent Solutions

Inc., a Nevada company that designs and manufactures advanced cogeneration energy systems for highly efficient on-location power generation; and two North Carolina companies, Jack Walters Inc. and Jack Walters Services, Inc. (collectively JWI). JWI designs, engineers, installs and maintains building automation systems that control heating, ventilation, air conditioning and lighting.

2. ***Interpath Communications, Inc.*** Interpath Communications, Inc. (Interpath), a majority-owned subsidiary, is a telecommunications company primarily engaged in providing Internet-based services. Interpath's services include consulting, design, implementation and support related to Internet access, Intranet development, electronic commerce, hosting and videoconferencing. During 1998, Interpath merged with TriNet Services, a leader in Internet professional services. The merger of the two companies has facilitated Interpath's ability to expand its market share of Internet services by combining Interpath's high-speed fiber optic network and support services with TriNet's Internet consulting and development capabilities.

Interpath also owns a 10% limited partnership interest in BellSouth Carolinas PCS, L.P. BellSouth Personal Communications, Inc. manages the partnership as the general partner. PCS is a wireless communications technology that provides high-quality mobile communications. The partnership serves PCS subscribers in North and South Carolina, and a small portion of Georgia, pursuant to a license issued by the Federal Communications Commission.

OTHER MATTERS

1. ***Safety Inspection Reports***. In April 1990, the FERC sent a letter to the Company providing comments on its review of the Company's Fifth (1987) Independent Consultant's Safety Inspection Report, which is required every five years under the FERC Regulation 18 CFR Part 12, for the Walters Hydroelectric Project and requested the Company to undertake certain supplemental analyses and investigations regarding the stability of the dam under extreme and improbable loading conditions. In November 1994, the Company submitted the independent consultant's report to the FERC regarding the stability of the dam at the Walters Project. The independent consultant concluded that the Walters dam has adequate structural stability and reserve capacity to resist both usual and unusual loading conditions without failure and that structural remediation is neither warranted nor recommended. In February 1997, the Company received a letter from the FERC pertaining to the Company's inspection report filed in November 1994. The FERC submitted comments on the inspection report and requested that further analysis be conducted. The Company filed a response in April 1997. In its response, the Company agreed with some of the FERC's comments and took exception to others. In November 1998, the Company received a letter from the FERC pertaining to the Company's April 1997 letter. The Company filed a response in December 1998, which provided information on a plan to further investigate the dam abutments and which addresses FERC's revised dynamic evaluation criteria. Depending on the outcome of these matters, the Company could be required to undertake efforts to enhance the stability of the dams. The cost and need for such efforts have not been determined. The Company cannot predict the outcome of this matter.

Similar letters were sent by the FERC during May 1990 with respect to the Company's Blewett and Tillery Hydroelectric Plants. The matters raised in the May 1990 letters from the FERC are still under investigation. Depending on the outcome of these matters, the Company could be required to undertake efforts to enhance the stability of the dams. The cost and need for such efforts have not been determined. The Company filed the Seventh (1998) Part 12 Report for the Tillery Hydroelectric Plant in November 1998 in accordance with a request from the FERC. The Tillery report does not indicate any deficiencies that would endanger the integrity of the dam. The consultant's Seventh Part 12 Report regarding the Blewett Hydroelectric Plant has been developed but, as requested by the FERC, has not been filed. The FERC is developing comments on earlier filings from the Company and has indicated that additional investigations and analyses may be required. The Company has agreed to await the comments from the FERC and incorporate the consultant's responses into the Seventh Part 12 Report. A review of

the draft of the Seventh Part 12 Report for Blewett reveals that the consultant did not identify any critical dam safety deficiencies. The Company cannot predict the outcome of this matter.

2. ***Marshall Hydroelectric Project***. In November 1991, the FERC notified the Company that the 5 MW Marshall Hydroelectric Project is no longer exempt from 18 CFR Part 12, Subpart C and D, dam safety regulations and that the plant's regulatory jurisdiction was being transferred from the NCUC to the FERC. This change resulted from updated dambreak flood studies which identified the potential impact on new downstream development, thus indicating the need to reclassify the project from a low hazard to a high hazard classification. In accordance with the change in regulatory jurisdiction, the Company developed an emergency action plan which meets the FERC guidelines and engaged its independent consultant to perform a safety inspection. In April 1992 the inspection report was submitted to the FERC for approval. In March 1995 the Company received comments on the inspection report from the FERC. As a result of these comments, and a meeting with the FERC officials, the Company was requested to perform further analyses and submit its findings to the FERC. The Company subsequently submitted the first phase of the requested analyses to the FERC in September 1995. Depending on the outcome of the FERC's review, the Company could be required to undertake efforts to enhance the stability of the Marshall dam and/or powerhouse. The cost and need for such efforts have not been determined. The Company cannot predict the outcome of this matter.

3. ***Tax Refund Dispute***. In April 1994, the Company filed a Complaint against the U.S. Government in the United States District Court for the Eastern District of North Carolina in Raleigh, North Carolina (Civil Action No. 5:94-CV-313-BR3) seeking a refund of approximately $188 million representing tax and interest related to depreciation deductions the Internal Revenue Service (IRS) previously disallowed for the years 1986 and 1987 on the Company's Harris Plant. The Company maintains that under applicable laws and regulations the Harris Plant was ready and available for operation in 1986. The IRS has previously denied some of the depreciation deductions on the Company's tax returns for the years in question on the ground that in its view the plant was not placed in service until 1987. During December 1995, the jury returned a verdict in favor of the U.S. Government. The Company has filed an appeal of the jury's verdict. The Company cannot predict the outcome of this matter.

4. ***Year 2000.*** See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussion of the Company's Year 2000 readiness issues.

OPERATING STATISTICS

	Years Ended December 31				
	1998	1997	1996	1995	1994
Energy supply (millions of kWh)					
Generated - coal	27,576	25,545	24,859	23,517	[illegible]
nuclear	22,014	21,690	20,284	19,949	[illegible]
hydro	790	799	882	824	[illegible]
combustion turbines	386	189	68	56	67
Purchased	5,675	6,318	7,292	7,433	7,039
Total energy supply (Company share)	56,441	54,541	53,385	51,779	47,502
Power Agency share (a)	4,349	4,101	3,616	3,828	3,236
Total system energy supply	60,790	58,642	57,001	55,607	50,738
Average fuel cost (per million BTU)					
Fossil	$ 1.71	$ 1.75	$ 1.75	$ 1.83	$ 1.78
Nuclear fuel	$ 0.46	$ 0.46	$ 0.45	$ 0.46	$ 0.47
All fuels	$ 1.14	$ 1.14	$ 1.14	$ 1.17	$ 1.14
Energy sales (millions of kWh)					
Retail					
Residential	13,117	12,488	12,611	12,074	11,147
Commercial	10,664	10,010	9,615	9,276	8,690
Industrial	14,911	15,073	14,456	14,312	14,030
Other Retail	1,357	1,294	1,263	1,288	1,263
Wholesale	14,427	13,900	13,383	12,940	10,442
Total energy sales	54,476	52,765	51,328	49,890	45,572
Company uses and losses	1,964	1,776	2,057	1,889	1,930
Total energy requirements	56,440	54,541	53,385	51,779	47,502
Customers billed					
Residential	996,398	972,385	945,703	920,495	894,616
Commercial	178,588	172,821	167,151	159,064	155,349
Industrial	5,056	5,072	5,066	4,863	4,845
Government and municipal	2,757	2,785	2,774	2,328	2,302
Resale	35	43	27	17	12
Total customers billed	1,182,834	1,153,106	1,120,721	1,086,767	1,057,124
Operating revenues (in thousands)					
Retail	$ 2,532,234	$ 2,450,509	$ 2,417,011	$ 2,399,354	$ [illegible]
Wholesale	539,984	518,438	523,988	560,676	[illegible]
Miscellaneous revenue	57,827	55,142	54,716	46,523	44,492
Total operating revenues	$ 3,130,045	$ 3,024,089	$ 2,995,715	$ 3,006,553	$ 2,876,589
Peak demand of firm load (thousands of kW)					
System	10,529	10,030	9,812	10,156	10,144
Company	9,875	9,344	9,264	9,500	9,642
Total capability at year-end (thousands of kW) (a)					
Fossil plants	6,571	6,571	6,331	6,331	6,331
Nuclear plants	3,174	3,064	3,064	3,064	3,064
Hydro plants	218	218	218	218	218
Purchased	1,538	1,588	1,603	1,592	1,596
Total system capability	11,501	11,441	11,216	11,205	11,209
Less Power Agency-owned portion (b)	593	690	686	682	654
Total Company capability	10,908	10,751	10,530	10,523	10,555

(a) Represents maximum dependable capacity of installed generating units plus other resources, including firm purchases. For 1998, total system capability during the summer was higher by 200 MW for term purchase contracts in place at time of summer peak.

(b) Net of the Company's purchases from Power Agency.

ITEM 2: PROPERTIES

In addition to the major generating facilities listed in PART I, ITEM 1, "Generating Capability", the Company also operates the following plants:

Plant	Location
1. Walters	North Carolina
2. Marshall	North Carolina
3. Tillery	North Carolina
4. Blewett	North Carolina
5. Weatherspoon	North Carolina
6. Morehead	North Carolina

The Company's sixteen power plants represent a flexible mix of fossil, nuclear and hydroelectric resources, with a total generating capacity (including Power Agency's share) of 9,963 MW. The Company's strategic geographic location facilitates purchases and sales of power with many other electric utilities, allowing the Company to serve its customers more economically and reliably. Major industries in the Company's service area include textiles, chemicals, metals, paper, food, rubber and plastics, wood products, and electronic machinery and equipment.

At December 31, 1998, the Company had 5,628 pole miles of transmission lines including 292 miles of 500 kV lines and 2,848 miles of 230 kV lines, and distribution lines of approximately 44,033 pole miles of overhead lines and approximately 12,759 miles of underground lines. Distribution and transmission substations in service had a transformer capacity of approximately 34,545 kVA in 2,035 transformers. Distribution line transformers numbered 420,633 with an aggregate 17,788,000 kVA capacity.

Power Agency has acquired undivided ownership interests of 18.33% in Brunswick Unit Nos. 1 and 2, 12.94% in Roxboro Unit No. 4 and 16.17% in Harris Unit No. 1 and Mayo Unit No. 1. Otherwise, the Company has good and marketable title to its principal plants and important units, subject to the lien of its Mortgage and Deed of Trust, with minor exceptions, restrictions, and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. The Company also owns certain easements over private property on which transmission and distribution lines are located.

The Company believes that its generating facilities are suitable, adequate, well-maintained and in good operating condition.

Plant Accounts (including nuclear fuel) - During the period January 1, 1994 through December 31, 1998, there were \$2,207,444,392 additions to the Company's utility plant accounts, \$717,984,814 retirements and \$(33,837,610) transfers and adjustments resulting in net additions of \$1,455,621,968. These net additions represent an increase of approximately 15.24%.

ITEM 3. LEGAL PROCEEDINGS

Legal and regulatory proceedings are included in the discussion of the Company's business in PART I, 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 1998.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age	Recent Business Experience
William Cavanaugh III	60	**President and Chief Executive Officer**, October 1996 to present; President and Chief Operating Officer, September 1992 to October 1996. Before joining the Company, Mr. Cavanaugh held various senior management and executive positions during a 23-year career with Entergy Corporation, an electric utility holding company with operations in Arkansas, Louisiana and Mississippi. Member of the Board of Directors of the Company since 1993.
Glenn E. Harder	48	**Executive Vice President and Chief Financial Officer**, Financial Services, August 1995 to present; Senior Vice President, Group Executive - Financial Services, October 1994 to August 1995. Before joining the Company, Mr. Harder held various senior management and executive positions with Entergy Corporation, an electric utility holding company with operations in Arkansas, Louisiana and Mississippi, and related entities.
William S. Orser	54	**Executive Vice President,** Energy Supply, June 1998 to present; Executive Vice President and Chief Nuclear Officer, December 1996 to June 1998; Executive Vice President - Nuclear Generation, April 1993 to December 1996. Prior to April 1993, Mr. Orser held various senior management and executive positions with Detroit Edison Company, and positions with Portland General Electric Company, Southern California Edison, and the U. S. Navy.
Tom D. Kilgore	51	**Senior Vice President**, Power Operations, August 1998 to present; President and Chief Executive Officer, Oglethorpe Power Corporation, Georgia Transmission Corporation and Georgia Operations Corporation, July 1991 to August 1998. These three companies provide power generation, transmission and system operations services, respectively, to 39 of Georgia's 42 customer-owned Electric Membership Corporations. From 1984 to July 1991, Mr. Kilgore held numerous management positions at Oglethorpe.
C.S. Hinnant	54	**Senior Vice President and Chief Nuclear Officer,** Nuclear Generation, June 1998 to present; Vice President, Brunswick Nuclear Plant, April 1997 to May 1998; Vice Present , Robinson Nuclear Plant, March 1994 to March 1997.
Fred N. Day, IV	55	**Senior Vice President,** Energy Delivery, July 1997 to present; Vice President, Western Region, 1995 to July 1997; Manager, Total Quality Performance, 1993 to 1995.
Cecil L. Goodnight	55	**Senior Vice President**, Retail Sales and Services, December 1998 to present; Senior Vice President and Chief Administrative Officer, Administrative Services, December 1996- December 1998; Senior Vice

President, Human Resources and Support Services, March 1995 to December 1996; Vice President, Human Resources (formerly Employee Relations Department), May 1983 to March 1995.

Robert B. McGehee	56	**Senior Vice President and General Counsel,** Administrative Services and Corporate Relations, December 1998 to present; Senior Vice President and General Counsel, Public and Corporate Relations, May 1997 to December 1998. From 1974 to May 1997, Mr. McGehee was a practicing attorney with Wise Carter Child & Caraway, a law firm in Jackson, Mississippi. He primarily handled corporate, contract, nuclear regulatory and employment matters. From 1987 to 1997 he managed the firm, serving as chairman of its Board from 1992 to May 1997.

PART II

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

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

1997	High	Low	Dividends Declared
First Quarter	$37 7/8	$36 1/8	$ .470
Second Quarter	36 1/4	33	.470
Third Quarter	36 5/8	33 3/4	.470
Fourth Quarter	42 1/2	34 5/16	.485

1998	High	Low	Dividends Declared
First Quarter	$45 3/4	$40 5/8	$ .485
Second Quarter	45 1/2	39 1/2	.485
Third Quarter	46 5/8	39 15/16	.485
Fourth Quarter	49 1/16	45 1/16	.500

The December 31 closing price of the Company's Common Stock was $42 3/8 in 1997 and $47 1/16 in 1998.

As of February 26, 1999, the Company had 67,089 holders of record of Common Stock.

2. Cancellation of Options to Repurchase Stock of Knowledge Builders. Inc.:

a) Securities Delivered. On November 30, 1998, the Company issued 6,609 shares of its Common Stock (Common Shares) to former holders of options to purchase shares of Knowledge Builders, Inc. (KBI) common stock as part of the second installment payment of consideration for the cancellation of those options under certain option surrender agreements executed in connection with the 1997 merger of KBI into a wholly-owned subsidiary of the Company (CaroCapital, Inc., a North Carolina enterprise corporation, since renamed Strategic Resource Solutions (SRS)).

b) Underwriters and Other Purchasers. No underwriters were used in connection with this issuance of Common Shares. The Common Shares were issued as consideration for the cancellation of the KBI options.

c) Consideration. The consideration for the Common Shares issued was the cancellation of the KBI options, which was a condition precedent to completion of the merger of KBI into SRS.

d) Exemption from Registration Claimed. The Common Shares described in this Item were issued on the basis of an exemption from registration under Section 4(2) of the Securities Act of 1933. The Common Shares were issued to a limited number of persons and are subject to restrictions on resale appropriate for private placements. Appropriate disclosure was made to all recipients of the Common Shares.

3. Installment Payment of Consideration for Acquisition of Parke Industries, Incorporated:

a) Securities Delivered. On February 5, 1999, 10,418 shares of the Company's Common Shares were delivered to a former shareholder of Parke Industries, Incorporated (Parke) pursuant to an asset purchase agreement, dated January 30, 1998, by and between SRS and Parke Industries, Incorporated. The asset purchase agreement provides that on each of the first three anniversaries of the closing of the above transaction, SRS is obligated to deliver Parke additional common shares having a market value of $540,000. The Common Shares delivered by SRS were acquired in market transactions and do not represent newly issued shares of the Company.

b) Underwriters and Other Purchases. No underwriters were used in connection with this issuance of Common Shares. The Common Shares were received by one individual.

c) Consideration. The consideration for the Common Shares was the delivery of certain assets of Parke.

d) Exemption from Registration Claimed. The Common Shares described in this Item were issued on the basis of an exemption from registration under Section 4(2) of the Securities Act of 1933. The Common Shares were received by one individual and are subject to restrictions on resale appropriate for private placement. Appropriate disclosure was made to the recipient of the Common Shares.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

The selected consolidated financial data should be read in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this report.

	Years Ended December 31				
	1998	1997	1996	1995	1994
	(dollars in thousands except per share data)				
Operating results					
Operating revenues	$ 3,130,045	$ 3,024,089	$ 2,995,715	$ 3,006,553	$ 2,876,589
Net income	$ 399,238	$ 388,317	$ 391,277	$ 372,604	$ 313,167
Earnings for common stock	$ 396,271	$ 382,265	$ 381,668	$ 362,995	$ 303,558
Ratio of earnings to fixed charges	4.38	4.17	4.12	3.67	3.31
Ratio of earnings to fixed charges and preferred stock dividends	4.28	3.98	3.83	3.43	3.09
Per share data					
Basic and diluted earnings per common share	$ 2.75	$ 2.66	$ 2.66	$ 2.48	$ 2.03
Dividends declared per common share	$ 1.955	$ 1.895	$ 1.835	$ 1.775	$ 1.715
Assets	$ 8,347,406	$ 8,176,728	$ 8,298,862	$ 8,159,655	$ 8,136,819
Capitalization					
Common stock equity	$ 2,949,305	$ 2,818,807	$ 2,690,454	$ 2,574,743	$ 2,586,179
Preferred stock - redemption not required	59,376	59,376	143,801	143,801	143,801
Long-term debt, net	2,614,414	2,415,656	2,525,607	2,610,343	2,530,773
Total capitalization	$ 5,623,095	$ 5,293,839	$ 5,359,862	$ 5,328,887	$ 5,260,753

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

RESULTS OF OPERATIONS FOR 1998 AS COMPARED TO 1997 AND 1997 AS COMPARED TO 1996

Operating Revenues

Operating revenue fluctuations as compared to the prior year are due to the following factors (in millions):

	1998	1997
Customer growth/changes in usage patterns	$ 82	$ 124
Price	(31)	(39)
Weather	27	(55)
Sales to Power Agency	25	(26)
Sales to other utilities	-	24
Other	3	-
Total	$ 106	$ 28

The increase in the customer growth/changes in usage patterns component of revenue for both comparison periods reflects continued growth in the number of customers served by the Company. While residential and commercial sales increased for both periods, industrial sales experienced a slight decrease in 1998. The price-related decrease in both comparison periods is primarily attributable to changes in the Power Coordination Agreement, that became effective in January 1997 and 1998, between the Company and North Carolina Electric Membership Corporation (NCEMC), as well as to decreases in the fuel cost component of revenue. The increase in the weather component of revenue for 1998 primarily results from a more favorable summer cooling season; the 1997 weather-related decrease reflects overall milder-than-normal weather conditions. The increase in revenue related to sales to the North Carolina Eastern Municipal Power Agency (Power Agency) during 1998 is primarily due to more favorable summer temperatures in 1998, as well as the timing of supplemental capacity adjustments. The decrease in sales to Power Agency in 1997 reflects the effects of milder weather during 1997, along with the increased availability of generating units owned jointly by the Company and Power Agency. Sales to other utilities increased during 1997 as a result of the Company's active pursuit of opportunities in the wholesale power market.

Operating Expenses

Fuel expense increased for both comparison periods primarily due to increases in generation of 5.3% and 4.6% during 1998 and 1997, respectively.

The decrease in purchased power in 1998 is primarily due to a 9.4% decrease in kilowatt hours (kWh) purchased, which was substantially offset by an increase in the average cost per kWh. The decrease in purchased power in 1997 is primarily a result of amendments to electric purchase power agreements between the Company and Cogentrix of North Carolina, Inc. and Cogentrix Eastern Carolina Corporation, which became effective in September 1996. In general, fluctuations in purchased power are affected by the availability and cost of Company generation and the cost of power on the wholesale market.

Other operation and maintenance expense has decreased since 1996 primarily due to reductions in administrative and general expenses. The decrease in 1998 was partially offset by expenses related to Hurricane Bonnie. Also contributing to the decrease in 1997 were lower expenses resulting from one less nuclear refueling outage and fewer fossil outages.

Pursuant to authorizations from the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC), the Company began to accelerate the amortization of certain regulatory assets over a three-year period beginning January 1997. For both 1998 and 1997, depreciation and amortization includes an additional $68 million resulting from this accelerated amortization. Depreciation and amortization expense also includes amortization of deferred operation and maintenance expenses associated with Hurricane Fran of approximately $12 million in both 1998 and 1997 and $4 million in 1996.

Harris Plant deferred costs, net, decreased in 1998 due to the completion, in late 1997, of the amortization of the Harris Plant phase-in costs related to the North Carolina retail jurisdiction.

Other Income (Expense)

The increase in losses from diversified business operations for both comparison periods represents the increase in combined pre-tax start-up losses of two of the Company's subsidiaries, Strategic Resource Solutions Corp. (SRS) and Interpath Communications, Inc. (Interpath). Management has projected losses for these subsidiaries as they evolve through start-up phases; however, 1998 operating losses for SRS were higher than management's expectations. Accordingly, the Company has initiated cost-cutting and revenue enhancing efforts at SRS to mitigate the effects of these losses and will continue to monitor its future performance. In 1998, SRS's results also include non-recurring charges of $7.5 million, primarily consisting of an investment write-off. Although not significantly affecting period-to-period comparisons, Interpath's results for all reported periods include losses recorded from its 10% limited partnership interest in BellSouth Carolinas PCS, LP (a wireless communications technology company).

The interest income fluctuation in both comparison periods is attributable to interest income of $11 million recorded in 1997, which was related to an income tax refund.

The $15.5 million change in other, net, for 1998 resulted from various items, none of which are individually significant. In 1996, other, net, was positively affected by an adjustment of $22.9 million to the unamortized balance of abandonment costs related to the Harris Plant.

Interest Charges

Other interest charges decreased in 1998, primarily as a result of a decrease in commercial paper borrowings classified as short-term debt during 1998.

Income Taxes

In general, income taxes fluctuate with changes in the Company's income before income taxes. In addition, income tax expense was affected in both comparison periods by tax provision adjustments recorded in 1997 and 1996 for potential audit issues in open tax years.

Preferred Stock Dividend Requirements

The decrease in the preferred stock dividend requirements for both comparison periods is the result of the redemption of two preferred stock series in July 1997.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow and Financing

The net cash requirements of the Company arise primarily from operational needs and support for investing activities, including replacement or expansion of existing facilities, construction to comply with pollution control laws and regulations, and investments in other business areas.

The Company has on file with the Securities and Exchange Commission (SEC) a shelf registration statement under which $1.5 billion aggregate principal amount of first mortgage bonds, senior notes and other debt securities are available for issuance by the Company. The Company can also issue up to $180 million of additional preferred stock under a shelf registration statement on file with the SEC.

The Company's ability to issue first mortgage bonds and preferred stock is subject to earnings and other tests as stated in certain provisions of its mortgage, as supplemented, and charter. The Company has the ability to issue an additional $4.6 billion in first mortgage bonds and an additional 27 million shares of preferred stock at an assumed price of $100 per share and a $5.85 annual dividend rate. The Company also has 10 million authorized preference stock shares available for issuance that are not subject to an earnings test.

As of December 31, 1998, the Company's revolving credit facilities totaled $750 million, all of which are long-term agreements supporting its commercial paper borrowings. The Company is required to pay minimal annual commitment fees to maintain its credit facilities. Consistent with management's intent to maintain its commercial paper on a long-term basis, and as supported by its long-term revolving credit facilities, the Company included in long-term debt all commercial paper outstanding as of December 31, 1998 and 1997, which amounted to $488.0 million and $245.9 million, respectively.

The proceeds from the issuance of commercial paper related to the credit facilities mentioned above and/or internally generated funds financed the retirement of long-term debt totaling $205 million in 1998. External funding requirements, which do not include early redemptions of long-term debt or redemptions of preferred stock, are expected to approximate $375 million, $500 million and $460 million in 1999, 2000 and 2001, respectively. These funds will be required for construction, mandatory retirements of long-term debt and general corporate purposes.

The Company's access to outside capital depends on its ability to maintain its credit ratings. The Company's first mortgage bonds are currently rated A2 by Moody's Investors Service, A by Standard & Poor's and A+ by Duff & Phelps. The Company's commercial paper is currently rated P-1, A-1 and D-1 by Moody's Investors Service, Standard & Poor's and Duff & Phelps, respectively.

The amount and timing of future sales of Company securities will depend upon market conditions and the specific needs of the Company. The Company may from time to time sell securities beyond the amount needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes.

In addition to the above, an anticipated issuance of common stock is discussed in the "NCNG Merger" discussion under OTHER MATTERS.

Capital Requirements

Estimated capital requirements for 1999 through 2001 primarily reflect construction expenditures to add generation, transmission and distribution facilities, as well as upgrade existing facilities. Those capital requirements are reflected in the following table (in millions):

	1999	2000	2001
Construction expenditures	$ 649	$ 860	$1,104
Nuclear fuel expenditures	77	93	64
AFUDC	(17)	(29)	(54)
Mandatory retirements of long-term debt	53	198	-
Total	$ 762	$ 1,122	$1,114

This table includes environmental expenditures relating to the Clean Air Act of approximately $27 million, and the NOx SIP Call of approximately $195 million.

In addition, the Company has total projected cash requirements of approximately $356 million for the years 1999 through 2001 relating to expenditures in other areas such as affordable housing investments and telecommunications infrastructure development. These projections are periodically reviewed and may change significantly.

The Company has two long-term agreements for the purchase of power and related transmission services from other utilities. The first agreement provides for the purchase of 250 megawatts of capacity through 2009 from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The second agreement is with Duke Energy (Duke) for the purchase of 400 megawatts of firm capacity through mid-1999. The estimated minimum annual payments for power purchases under these agreements are approximately $31 million for Rockport and $48 million for Duke, representing capital-related capacity costs. In 1998, total purchases (including transmission use charges) under the Rockport and Duke agreements amounted to $59.3 million and $75.5 million, respectively.

In addition, pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between the Company and Power Agency, the Company is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant through 2007. The estimated minimum annual payments for these purchases, representing capital-related capacity costs, total approximately $26 million. Purchases under the agreement with Power Agency totaled $34.4 million in 1998.

OTHER MATTERS

Retail Rate Matters

A petition was filed in July 1996 by the Carolina Industrial Group for Fair Utility Rates (CIGFUR) with the NCUC, requesting that the NCUC conduct an investigation of the Company's base rates or treat its petition as a complaint against the Company. The petition alleged that the Company's return on equity (which was authorized by the NCUC in the Company's last general rate proceeding in 1988) and earnings are too high. In December 1996, the NCUC issued an order denying CIGFUR's petition and stating that it tentatively found no reasonable grounds to proceed with CIGFUR's petition as a complaint. Subsequently, CIGFUR filed a Motion for Reconsideration with the NCUC and a Notice of Appeal with the North Carolina Court of Appeals, both of which were denied. On December 4, 1998, a petition for Discretionary Review filed by CIGFUR was denied by the North Carolina Supreme Court.

In late 1998 and early 1999, the Company filed, and the respective commissions subsequently approved, proposals in the North and South Carolina retail jurisdictions to accelerate cost recovery of its nuclear generating assets beginning January 1, 2000 and continuing through 2004. The accelerated cost recovery begins immediately after the 1999 expiration of the accelerated amortization of certain regulatory assets, which began in January 1997. Pursuant to the orders, the Company's depreciation expense for nuclear generating assets will increase by $106 million to $150 million per year. Recovering the costs of the nuclear generating assets on an accelerated basis will better position the Company for the uncertainties associated with potential restructuring of the electric utility industry.

Environmental

The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters.

Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under various federal and state laws. There are several manufactured gas plant (MGP) sites to which the Company and certain entities that were later merged into the Company had some connection. In this regard, the Company, along with others, is participating in a cooperative effort with the North Carolina Department of Environment and Natural Resources, Division of Waste Management (DWM), which has established a uniform framework to address MGP sites. The investigation and remediation of specific MGP sites will be addressed pursuant to one or more Administrative Orders on Consent (AOC) between the DWM and the potentially responsible party or parties. The Company has signed AOCs to investigate certain sites. The Company continues to investigate the identities of parties connected to individual MGP sites, the relative relationships of the Company and other parties to those sites and the degree to which the Company will undertake efforts with others at individual sites. The Company does not expect the costs associated with these sites to be material to the financial position and results of operations of the Company.

The Company has been notified by regulators of its involvement or potential involvement in several sites, other than MGP sites, that may require investigation and/or remediation. Although the Company may incur costs at these sites, the investigation and/or remediation of the sites has not advanced to a stage where reasonable cost estimates can be made. The Company cannot predict the outcome of these matters.

The Company carries a liability for the estimated costs associated with certain remedial activities. This liability is not material to the financial position of the Company.

The 1990 amendments to the Clean Air Act (Act) require substantial reductions in sulfur dioxide and nitrogen oxides emissions from fossil-fueled electric generating plants. The Act will require the Company to meet more stringent provisions effective January 1, 2000. The Company plans to meet the sulfur dioxide emissions requirements by utilizing the most economical combination of fuel-switching and sulfur dioxide emission allowances. Installation of additional equipment will be necessary to reduce nitrogen oxide emissions. The Company estimates that future capital expenditures necessary to meet the nitrogen oxide emission requirements will approximate $27 million. Increased operation and maintenance costs, including emission allowance expense, and increased fuel costs are not expected to be material to the Company's results of operations.

On October 27, 1998, the Environmental Protection Agency (EPA) published a final rule addressing the issue of regional transport of ozone. This rule is commonly known as the NOx SIP call. The EPA's rule requires 22 states, including North and South Carolina, to further reduce nitrogen oxide emission in order to attain a pre-set state NOx emission level by May 2003. The EPA's rule also suggests to the states that these additional nitrogen oxide emission reductions be obtained from the utility sector. The Company is evaluating necessary measures to comply with the rule and estimates its related capital expenditures through 2003 could be approximately $327 million. Increased operation and maintenance costs relating to the NOx SIP call are not expected to be material to the Company's results of operations. The Company and the states of North and South Carolina are participating in litigation challenging the NOx SIP call. The Company cannot predict the outcome of this matter.

With regard to revisions to existing air quality standards, in July 1997 the EPA issued final regulations establishing a new fine-particulate standard. These regulations may require the installation of additional control equipment at some of the Company's fossil-fueled electric generating plants. The Company is evaluating the effects of these and other similar regulations and cannot determine the estimated costs that may be required for compliance. The Company cannot predict the outcome of this matter.

Nuclear

In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC and the SCPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdiction, the provisions for nuclear decommissioning costs are based on amounts agreed upon in applicable rate agreements. Based on the site-specific estimates discussed below, and using an assumed after-tax earnings rate of 7.75% and an assumed cost escalation rate of 4%, current levels of rate recovery for nuclear decommissioning costs are adequate to provide for decommissioning of the Company's nuclear facilities.

The Company's most recent site-specific estimates of decommissioning costs were developed in 1998, using 1998 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring shortly after operating license expiration. These estimates, in 1998 dollars, are $279.8 million for Robinson Unit No. 2, $299.3 million for Brunswick Unit No. 1, $298.5 million for Brunswick Unit No. 2 and $328.1 million for the Harris Plant. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to Power Agency, which holds an undivided ownership interest in the Brunswick and Harris nuclear generating facilities. Operating licenses for the Company's nuclear units expire in the year 2010 for Robinson Unit No. 2, 2016 for Brunswick Unit No. 1, 2014 for Brunswick Unit No. 2 and 2026 for the Harris Plant.

The Financial Accounting Standards Board is proceeding with its project regarding accounting practices related to obligations associated with the retirement of long-lived assets, and an exposure draft of a proposed accounting standard is expected to be issued during the first half of 1999. It is uncertain when a final statement will be issued and what effects it may ultimately have on the Company's accounting for nuclear decommissioning and other retirement costs.

As required under the Nuclear Waste Policy Act of 1982, the Company entered into a contract with the U.S. Department of Energy (DOE) under which the DOE agreed to begin taking spent nuclear fuel by January 31, 1998. The DOE defaulted on its January 31, 1998 obligation to begin taking spent nuclear fuel, and a group of utilities, including the Company, has undertaken measures to force the DOE to take spent nuclear fuel. To date, the courts have rejected these attempts. In addition, several utilities have filed actions for damages in the United States Court of Claims, and in some of those cases the Court has agreed that the DOE has breached its contract for disposal of spent nuclear fuel. The Company is in the process of evaluating whether it should file a similar action for damages. The Company will also monitor legislation that has been introduced in Congress that would provide for interim storage of spent nuclear fuel at a storage facility operated by the DOE. The Company cannot predict the outcome of this matter.

With certain modifications and additional approval by the Nuclear Regulatory Commission (NRC), the Company's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on the Company's system through the expiration of the current operating licenses for all of the Company's nuclear generating units. Subsequent to the expiration of these licenses, dry storage may be necessary. The Company has initiated the process of obtaining the additional NRC approval.

NCNG Merger

On November 10, 1998, the Company and North Carolina Natural Gas Corporation (NCNG) entered into an Agreement and Plan of Merger (Merger Agreement) providing for the strategic business combination of the Company and NCNG in a stock-for-stock transaction. Upon consummation of the proposed merger, NCNG will be a wholly owned subsidiary of the Company. The Company will issue approximately $354 million in stock to NCNG shareholders to complete the merger. The merger transaction is intended to constitute a tax-free reorganization for federal income tax purposes and to be accounted for as a pooling-of-interests. The Merger Agreement has been approved by the Boards of Directors of the Company and NCNG, and consummation of the merger is expected in mid-1999. There are certain closing conditions, including approval by the shareholders of NCNG and certain regulatory agencies, and the filing of notifications required by the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The Company and NCNG filed a joint application for approval of the merger with the NCUC on January 11, 1999. The Company filed a similar request with the SCPSC on February 9, 1999.

NCNG, headquartered in Fayetteville, North Carolina, is a natural gas distribution utility. NCNG sells and transports natural gas to residential, commercial, industrial and electric power generation customers. NCNG provides natural gas, propane and related services to more than 173,000 retail customers in 86 towns and cities and to four municipal gas distribution systems in south central and eastern North Carolina. Much of that area is also part of the Company's service territory. The ability to offer natural gas to customers has been a priority for the Company as part of its strategy to become a total energy provider while securing fuel supplies for planned gas-fired electric generation. The Company's merger with NCNG advances that strategy.

Diversified Businesses

Strategic Resource Solutions Corp. (SRS), a wholly owned subsidiary, specializes in facilities and energy management software, systems and services for educational, commercial, industrial and governmental markets nationwide. During 1998, SRS acquired the following companies: Parke Industries Inc., a lighting retrofit company located in California; Intelligent Solutions Inc., a Nevada company that designs and manufactures advanced cogeneration energy systems for highly efficient on-location power generation; and two North Carolina companies, Jack Walters Inc. and Jack Walters Services, Inc. (collectively JWI). JWI designs, engineers, installs and maintains building automation systems that control heating, ventilation, air conditioning and lighting.

Interpath Communications, Inc. (Interpath), a majority-owned subsidiary, is a telecommunications company primarily engaged in providing Internet-based services. Interpath's services include consulting, design, implementation and support related to Internet access, Intranet development, electronic commerce, hosting and videoconferencing. During 1998, Interpath merged with TriNet Services, a leader in Internet professional services. The merger of the two companies has facilitated Interpath's ability to expand its market share of Internet services by combining Interpath's high-speed fiber optic network and support services with TriNet's Internet consulting and development capabilities.

Interpath also owns a 10% limited partnership interest in BellSouth Carolinas PCS, L.P. BellSouth Personal Communications, Inc. manages the partnership as the general partner. PCS is a wireless communications technology that provides high-quality mobile communications. The partnership serves PCS subscribers in North and South Carolina, and a small portion of Georgia, pursuant to a license issued by the Federal Communications Commission.

Competition

General

In recent years, the electric utility industry has experienced a substantial increase in competition at the wholesale level, caused by changes in federal law and regulatory policy. Several states have also decided to restructure aspects of retail electric service. The issue of retail restructuring and competition is being reviewed by a number of states and bills have been introduced in Congress that seek to introduce such restructuring in all states.

Allowing increased competition in the generation and sale of electric power will require resolution of many complex issues. One of the major issues to be resolved is who will pay for stranded costs. Stranded costs are those costs and investments made by utilities in order to meet their statutory obligation to provide electric service, but which could not be recovered through the market price for electricity following industry restructuring. The amount of stranded costs that the Company might experience would depend on the timing of, and the extent to which, direct competition is introduced, and the then-existing market price of energy. If electric utilities were no longer subject to cost-based regulation and it were not possible to recover stranded costs, the financial position and results of operations of the Company could be adversely affected.

Wholesale Competition

Since passage of the National Energy Act of 1992 (Energy Act), competition in the wholesale electric utility industry has significantly increased due to a greater participation by traditional electricity suppliers, wholesale power marketers and brokers, and due to the trading of energy futures contracts on various commodities exchanges. This increased competition could affect the Company's load forecasts, plans for power supply and wholesale energy sales and related revenues. The impact could vary depending on the extent to which additional generation is built to compete in the wholesale market, new opportunities are created for the Company to expand its wholesale load, or current wholesale customers elect to purchase from other suppliers after existing contracts expire.

To assist in the development of wholesale competition, in 1996 the Federal Energy Regulatory commission (FERC) issued standards for wholesale wheeling of electric power through its rules on open access transmission and stranded costs and on information systems and standards of conduct (Orders 888 and 889). The rules require all transmitting utilities to have on file an open access transmission tariff, which contains provisions for the recovery of stranded costs and numerous other provisions that could affect the sale of electric energy at the wholesale level. The Company filed its open access transmission tariff with the FERC in mid-1996. Shortly thereafter, Power Agency and other entities filed protests challenging numerous aspects of the Company's tariff and requesting that an evidentiary proceeding be held. The FERC set the matter for hearing and set a discovery and procedural schedule. In July 1997, the Company filed an offer of settlement in this matter. The administrative law judge certified the offer to the full FERC in September 1997. The offer is pending before the FERC. The Company cannot predict the outcome of this matter.

In November 1997, the Company applied to the FERC for authority to sell power at market-based rates. In January 1998, the FERC issued an order accepting the Company's application and permitting the Company to sell power at market-based rates. Excluding sales under specific long-term wholesale agreements, the Company makes virtually all of its wholesale power sales under its market-based rate tariff.

During the last week of June 1998, some wholesale power markets experienced sharp increases in prices. That upsurge in power costs was due, in part, to the unavailability of generating capacity and unusually hot weather in the Midwestern portion of the country. The relatively sudden movement in wholesale power prices disrupted certain power transactions, including some to which the Company was a party. The monetary damages the Company incurred as a result of those disrupted transactions did not have a material adverse effect on the Company's financial position and results of operations. The Company has taken steps to mitigate those monetary damages. The Company anticipates increased volatility in the wholesale power market during peak demand periods; however, due to the risk management processes the Company has in place, the Company does not expect this volatility to have a material adverse effect on its financial position and results of operations.

Retail Competition

The Energy Act prohibits the FERC from ordering retail wheeling - transmitting power on behalf of another producer to an individual retail customer. Several states have changed their laws and regulations to allow full retail competition. Other states are considering changes to allow retail competition. These changes and proposals have taken differing forms and included disparate elements. The Company believes changes in existing laws in both North and South Carolina would be required to permit competition in the Company's retail jurisdictions.

North Carolina Activities

Since 1995, the NCUC has been considering the impact of increased competition in the electric utility industry. In May 1996, the NCUC issued an order stating that the FERC Orders 888 and 889 would provide a new focus for NCUC proceedings with respect to competition in the electric industry. As a result, the NCUC held Docket No. E-100, Sub 77, which concerned retail competition, in abeyance pending further order and established a new docket (Docket No. E-100, Sub 78) to address the FERC Orders 888 and 889. The NCUC has received several rounds of comments in this docket; the Company filed its most recent comments and reply comments in November 1997 and December 1997, respectively. By order issued June 18, 1998, the Commission held that this docket would also be held in abeyance pending further order. The Company cannot predict the outcome of this matter.

In April 1997, the North Carolina General Assembly (General Assembly) approved legislation establishing a 23-member study commission to evaluate the future of electric service in the state. During 1998, the study commission met and held public hearings around the state. The commission also retained consultants to conduct analyses and studies concerning various restructuring issues, including stranded costs, state and local tax implications and electric rate comparisons. In June 1998, the study commission issued an interim report to the 1998 General Assembly, summarizing the numerous fact-finding and educational activities and analytical projects the commission had initiated or completed. That report offered no judgments or recommendations. The commission is scheduled to make its final report to the 1999 Session of the General Assembly which will begin in 1999 and continue during 2000. The Company cannot predict the outcome of this matter.

South Carolina Activities

The South Carolina General Assembly ended its 1998 session without enacting any legislation regarding electric restructuring. On October 29, 1998, the South Carolina Senate Judiciary Committee appointed a 13-member task force to study the restructuring issue and make a report to the South Carolina General Assembly during the 1999 legislative session. The task force was subsequently expanded to 18 members, including the Company. The General Assembly's House Utility Subcommittee is also expected to continue pursuing the issue during that session. The Company cannot predict the outcome of these matters.

Federal Activities

At the federal level, additional bills regarding restructuring of the electric utility industry were introduced in 1998, but Congress adjourned in October without taking any action on the issue. The debate regarding industry restructuring is expected to continue in Congress in 1999. The Company cannot predict the outcome of this matter.

Company Activities

The developments described above have created changing markets for energy. As a strategy for competing in these changing markets, the Company is becoming a total energy provider in the region by providing a full array of energy-related services to its current customers and expanding its market reach. As part of this strategy, the Company plans to position itself as a supplier of natural gas to its customers. The Company took a major step towards reaching this goal on November 10, 1998 by entering into the Merger Agreement with NCNG.

The Company currently plans to construct approximately 2300 MW of new generating facilities by the year 2002. These facilities, including two combustion turbine facilities outside of the Company's current service area, will help the Company continue to meet the needs of its growing retail customer base and increase its ability to participate in the wholesale energy supply business.

The Company's strategy for addressing the planning uncertainty and risks created by the changing markets for energy includes securing long-term contracts with its wholesale customers, continuing to work to meet the energy needs of its industrial customers, promoting economic development, implementing new marketing strategies, improving customer satisfaction, and increasing the focus on managing and reducing costs and, consequently, avoiding future rate increases.

In 1996, Power Agency notified the Company that it would discontinue certain contractual purchases of power from the Company effective September 1, 2001; however, the Company won the right to continue supplying this power by being selected from a number of bidders. On September 11, 1998, the Company and Power Agency entered into a revised agreement that extends the period during which Power Agency will continue to purchase all of its supplemental power from the Company through at least December 31, 2002. The new agreement also includes options for Power Agency to purchase supplemental power from the Company for the year 2003 and beyond. The load served by supplemental power under that agreement will include all of Power Agency's power needs in excess of the load served by Power Agency through its ownership interest in generation units that it jointly owns with the Company and other smaller resources that are currently in place. The revised agreement was filed with, and has been accepted by, the FERC.

On October 9, 1998, the Company and its largest customer, NCEMC, entered into an agreement under which NCEMC will purchase a total of 800 MWs of peaking capacity and associated energy from the Company during the period from January 1, 2001 through December 31, 2003. The agreement, which provides NCEMC with an option to extend all or part of the purchase through 2005, provides capacity to meet NCEMC's growing peaking power needs. A portion of this purchase is intended to serve load located in the Company's service area that is currently served by purchases from the Company under a contract that will expire on December 31, 2000. During the period 2001 through 2003, this agreement also will serve up to 450 MWs of NCEMC's load that is located in the Duke Power service area that has not previously been served by the Company. The agreement will be filed with the FERC for approval or acceptance. The Company cannot predict the outcome of this matter.

On October 30, 1998, the Company and NCEMC also entered into agreements that supersede the 1993 Power Coordination Agreement between the Company and NCEMC, as amended (the PCA). The primary effect of the new agreements is to unbundle the generation and transmission service for the load previously served under the PCA. To that end, the parties executed a Network Integration Transmission Service Agreement and a Network Operating Agreement under which NCEMC will receive transmission services from the Company pursuant to the Company's Open Access Transmission Tariff. The parties also entered into a new Power Supply Agreement, which provides for the Company to sell capacity and energy to NCEMC under terms and conditions and in amounts that are substantially the same as those that were set forth in the PCA. The parties agreed to a modification of the calculation of certain capacity charges; however, the net effect of the changes is intended to be essentially revenue neutral under expected load conditions. The Network Integration Transmission Service Agreement, the Network Operating Agreement and the new Power Supply Agreement were filed with FERC on November 3, 1998 and have been accepted. The new Power Supply Agreement has also been submitted by NCEMC to the Rural Utilities Service for approval. The Company cannot predict the outcome of this matter.

On September 28, 1998, the Company and the South Carolina Public Service Authority (Santee Cooper) entered into an agreement under which the Company will provide peaking capacity and associated energy to Santee Cooper for the period January 1, 1999 through December 31, 2003. Under the terms of the agreement, the Company will provide 100 MW of generation capacity in 1999, 150 MW in 2000 and 200 MW from 2001 to 2003. The agreement was filed with, and has been accepted by, the FERC.

As a regulated entity, the Company is subject to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation", (SFAS-71). Accordingly, the Company records certain assets and liabilities resulting from the effects of the ratemaking process, which would not be recorded under generally accepted accounting principles for unregulated entities. The Company's ability to continue to meet the criteria for application of SFAS-71 may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS-71 no longer applied to a separable portion of the Company's operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment of electric utility plant assets as determined pursuant to Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of".

Year 2000

Background

The Company's overall goal is to be Year 2000 ready, and its efforts to reach this goal are on target. "Year 2000 ready" means that critical systems, devices, applications or business relationships have been evaluated and are expected to be suitable for continued use into and beyond the Year 2000, or contingency plans are in place.

The Company began addressing the Year 2000 issue in 1994 by beginning to assess its business computer systems, such as general ledger, payroll, customer billing and inventory control. The majority of these systems have been corrected and running in the Company's day-to-day computing environment since 1996. Also, by the mid-1990s, two major accounting systems were replaced with systems that were designed to be Year 2000 ready. The Company had substantially addressed the remaining business systems by the end of 1998 and will conduct supplementary testing in 1999, as appropriate.

During mid-1997, a Corporate Year 2000 Project was established to provide leadership and direction to the Year 2000 efforts throughout the Company and its subsidiaries. Also, the project scope was expanded to include "embedded" systems (such as process control computers, chart recorders, data loggers, calibration equipment and chemical analysis equipment), end-user computing hardware and software (including personal computers, spreadsheets, word processing and other personal and workgroup applications), plant and corporate facilities (such as security systems, elevators and heating and cooling systems) and business relationships with key suppliers and customers.

The Company is using a multi-step approach in conducting its Year 2000 Project and currently plans to complete the project by August 1999. These steps are: inventory, assessment, remediation and testing, and contingency planning. The first step, an inventory of all systems and devices with potential Year 2000 problems, was completed in January 1998. The next step, completed in the first half of 1998, was to conduct an initial assessment of the inventory to determine the state of its Year 2000 readiness. As part of the assessment phase, remediation strategies were identified and remediation cost estimates were developed. The Company is currently utilizing both internal and external resources to remediate and test for Year 2000 readiness. The Company's primary approach has been for the Corporate Year 2000 Program Office to provide overall leadership and direction and assign responsibility to individual departments and business units for Year 2000 readiness in their respective areas. Staffing decisions regarding the labor required to complete the project are made at the department/business unit level. Several hundred of the Company's employees as well as contract personnel have been used on this effort. Vendor labor is also occasionally used.

Several external reviews of the project have been conducted to validate the reliability of risk and cost estimates as well as work processes and work products. These have included project reviews by two consulting firms, an embedded systems audit by an engineering firm and a legal review by an external law firm. In addition, the Company is actively conducting formal communications with the suppliers and customers with which it has active contracts to determine the extent to which the Company is vulnerable to those third parties' failure to remediate their own Year 2000 issues. The Company ranked its vendors and suppliers to identify those considered to be critical. Those identified as critical include telecommunications providers, fuel suppliers (nuclear, coal, natural gas and other), transportation carriers, vendors of certain nuclear systems and components, vendors of fossil power plant digital control systems and financial services suppliers. The Company cannot predict the outcome of other companies' remediation efforts.

Costs

As of January 31, 1999, the total remaining cost of the Year 2000 Project is estimated at $12 million. This estimate excludes Year 2000 Project costs attributable to recent subsidiary acquisitions, which the Company does not expect to be material to its financial position and results of operations. Approximately $4 million is for new software and hardware purchases and will be capitalized. The remaining $8 million will be expensed as incurred. Through December 1998, the Company had incurred and expensed approximately $8 million related to the inventory, assessment and remediation of non-compliant systems, equipment and applications. The costs of the project and the date on which the Company plans to complete the Year 2000 modifications are based on management's best estimates, which were derived using assumptions of future events including the continued availability of certain resources, third parties' Year 2000 readiness

and other factors.

Risk Assessment

At this time, the Company believes its most reasonably likely worst case scenario is that key customers could experience significant reductions in their power needs due to their own Year 2000 issues. The Company is conducting informal meetings with its largest wholesale, industrial and commercial customers and is holding information sharing forums to gather information on Year 2000 readiness. Based on the information provided through these contacts, the Company has not identified any major customer that appears to be at significant risk of not being Year 2000 ready. For this reason, the Company does not believe that this scenario is likely to occur. Nonetheless, the Company has assessed the effect of such a scenario by using current financial data. That data indicates that if the Company's twenty key industrial customers experienced significant reduced power needs for a period of one month, the Company's revenues would decrease by approximately 6% for that month.

An alternative worst-case scenario includes the effect of cascading disruptions caused by other entities whose electrical systems are connected to the Company's. The Company has assessed the risk of this scenario, believes that its contingency plans would mitigate the long-term occurrence of such a scenario, and does not expect that it would have a material adverse effect on its financial position and results of operations.

Contingency Plans

Contingency plans are being prepared to help ensure that the Company's critical business processes will continue to function on January 1, 2000 and beyond. The Company's contingency plans are being structured to address both remediation of systems and their components and overall business operating risk. These plans are intended to mitigate internal risks, as well as potential risks in the supply chain of the Company's suppliers and customers. The Company's contingency plans will be developed by June 30, 1999 in accordance with the target dates established by the NRC and the North American Electric Reliability Council (NERC).

The Company is developing contingency plans to mitigate the risk associated with the failure of critical vendors or suppliers. Based on the Company's assessment of the risk of non-compliance, the Company will take action up to and including entering into a business relationship with an alternate vendor or supplier.

One of the Company's emergency contingency plans specifically addresses emergency scenarios that may arise due to the fact that electric utility systems throughout the southeast region of the United States are interconnected. The Company has been working actively with the NERC and the Southeastern Electric Reliability Council to address the issue of overall grid reliability and protection. In order to mitigate the risk of cascading regional electric failures, the Company can, as a last resort, isolate its transmission system either automatically or manually. The Company's emergency readiness contingency plan includes the performance of regular training exercises that include simulated disaster recovery scenarios. As part of its Year 2000 contingency planning, the Company will review its disaster recovery scenarios to identify those that can be used specifically for Year 2000 readiness training.

New Accounting Standard

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS-133), effective for fiscal years beginning after June 15, 1999. SFAS-133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recognition of all derivative instruments as assets or liabilities in the statement of financial position and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not an instrument qualifies as a hedge and, if so, the type of hedge. The Company has not completed its analysis of the provisions of SFAS-133 nor its effect on the Company.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to certain market risks that are inherent in the Company's financial instruments, which arise from transactions entered into in the normal course of business. The Company's primary exposures are changes in interest rates with respect to its long-term debt and commercial paper, and fluctuations in the return on marketable securities with respect to its nuclear decommissioning trust funds. These financial instruments are held for purposes other than trading. The risks discussed below do not include the price risks associated with nonfinancial instrument transactions and positions associated with the Company's operations, such as sales commitments and inventory.

Interest Rate Risk: The Company manages its interest rate risks through use of a combination of fixed and variable rate debt. Variable rate debt has rates that adjust in periods ranging from daily to monthly. Interest rate derivative instruments may be used to adjust interest rate exposures and to protect against adverse movements in rates. The table below presents principal cash flows and related weighted-average interest rates, by maturity date, for the Company's long-term debt and commercial paper at December 31, 1998, including current portions. In addition, the Company has an interest rate lock to hedge an anticipated issuance of long-term debt in 1999. The interest rate lock has a notional amount of $150 million. Settlement of the interest rate lock is based on the ten-year Treasury rate at the strike date. At December 31, 1998, the interest rate lock had a fair value asset position of approximately $1 million.

	1999	2000	2001	2002	2003	Thereafter	Total	Fair Value
(Dollars in millions)								
Fixed rate long-term debt	$ 53	$ 198	-	$ 100	$ 5	$1,219	$1,575	$1,686
Average interest rate	7.10%	5.92%	-	6.75%	6.44%	7.41%	7.17%	
Variable rate long-term debt	-	-	-	-	-	$ 620	$ 620	$ 622
Average interest rate	-	-	-	-	-	3.67%	3.67%	
Commercial paper	$ 488	-	-	-	-	-	$ 488	$ 488
Average interest rate	5.22%	-	-	-	-	-	5.22%	

The fixed and variable rate debt principal cash flows reflected in the table above are substantially the same as reported at December 31, 1997 for post-1998 debt. Commercial paper outstanding at December 31, 1997 totaled approximately $246 million.

Marketable Securities Return Risk: The Company maintains trust funds, as required by the Nuclear Regulatory Commission, to fund certain costs of decommissioning. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 1998 and 1997, the fair values of these funds were approximately $311 million and $246 million, respectively. The Company actively monitors its portfolio by benchmarking the performance of its investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that costs are recovered through the Company's regulated electric rates and, therefore, fluctuations in trust fund marketable security returns do not affect the earnings of the Company.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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Consolidated Financial Statements:	
Consolidated Statements of Income for the Years Ended December 31, 1998, 1997, and 1996	49
Consolidated Balance Sheets as of December 31, 1998 and 1997	50
Consolidated Statements of Cash Flow for the Years Ended December 31, 1998, 1997 and 1996	51
Consolidated Schedules of Capitalization as of December 31, 1998 and 1997	52
Consolidated Statements of Retained Earnings for the Years Ended December 31, 1998, 1997 and 1996	53
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Notes to Consolidated Financial Statements	54
Consolidated Financial Statement Schedules for the Years Ended December 31, 1998, 1997 and 1996:	
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All other schedules have been omitted as not applicable or not required or because the information required to be shown is included in the Consolidated Financial Statements or the accompanying Notes to the Consolidated Financial Statements.

INDEPENDENT AUDITORS' REPORT

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF CAROLINA POWER & LIGHT COMPANY:

We have audited the accompanying consolidated balance sheets and schedules of capitalization of Carolina Power & Light Company and subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1998. Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Carolina Power & Light and subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We have also previously audited, in accordance with generally accepted auditing standards, the consolidated balance sheets and schedules of capitalization as of December 31, 1996, 1995 and 1994, and the related consolidated statements of income, retained earnings and cash flows for the years ended December 31, 1995 and 1994 (none of which are presented herein); and we expressed unqualified opinions on those financial statements.

In our opinion, the information set forth in the selected financial data for each of the five years in the period ended December 31, 1998, and appearing at Item 6, is fairly presented in all material respects in relation to the consolidated financial statements from which it has been derived.

/s/ DELOITTE & TOUCHE LLP
Raleigh, North Carolina
February 9, 1999

CONSOLIDATED STATEMENTS of INCOME

(In thousands except per share data)	1998	1997	1996
	Years ended December 31		
Operating revenues	**$3,130,045**	$3,024,089	$2,995,715
Operating expenses			
Fuel	**571,419**	534,268	515,050
Purchased power	**382,547**	387,296	412,554
Other operation and maintenance	**642,478**	661,466	730,140
Depreciation and amortization	**487,097**	481,650	386,927
Taxes other than on income	**141,504**	139,478	140,479
Harris Plant deferred costs, net	**7,489**	24,296	26,715
Total operating expenses	**2,232,534**	2,228,454	2,211,865
Operating income	**897,511**	795,635	783,850
Other income (expense)			
Diversified business operations	**(70,345)**	(25,278)	(4,729)
Interest income	**9,526**	18,335	4,063
Harris Plant carrying costs	**3,785**	4,626	7,299
Other, net	**(9,509)**	6,003	42,080
Total other income (expense)	**(66,543)**	3,686	48,713
Income before interest charges and income taxes	**830,968**	799,321	832,563
Interest charges			
Long-term debt	**169,901**	163,468	172,622
Other interest charges	**11,156**	18,743	19,155
Allowance for borrowed funds used during construction	**(6,821)**	(4,923)	(6,407)
Total interest charges, net	**174,236**	177,288	185,370
Income before income taxes	**656,732**	622,033	647,193
Income taxes	**257,494**	233,716	255,916
Net income	**$ 399,238**	$ 388,317	$ 391,277
Preferred stock dividend requirements	**(2,967)**	(6,052)	(9,609)
Earnings for common stock	**$ 396,271**	$ 382,265	$ 381,668
Average common shares outstanding	**143,941**	143,645	143,621
Basic and diluted earnings per common share	**$ 2.75**	$ 2.66	$ 2.66
Dividends declared per common share	**$1.955**	$1.895	$1.835

See notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(In thousands)	December 31	
Assets	**1998**	*1997*
Electric utility plant		
Electric utility plant in service	**$10,280,638**	$10,113,334
Accumulated depreciation	**(4,496,632)**	(4,181,417)
Electric utility plant in service, net	**5,784,006**	5,931,917
Held for future use	**11,984**	12,255
Construction work in progress	**306,866**	158,347
Nuclear fuel, net of amortization	**196,684**	190,991
Total electric utility plant, net	**6,299,540**	6,293,510
Current assets		
Cash and cash equivalents	**28,872**	14,426
Accounts receivable	**406,418**	406,872
Fuel	**78,086**	47,551
Materials and supplies	**146,615**	136,253
Deferred fuel cost	**42,647**	20,630
Prepayments	**63,809**	62,040
Other current assets	**34,409**	47,034
Total current assets	**800,856**	734,806
Deferred debits and other assets		
Income taxes recoverable through future rates	**277,894**	328,818
Abandonment costs	**16,083**	38,557
Harris Plant deferred costs	**60,021**	63,727
Unamortized debt expense	**27,010**	48,407
Nuclear decommissioning trust funds	**310,702**	245,523
Miscellaneous other property and investments	**294,678**	212,291
Other assets and deferred debits	**260,622**	211,089
Total deferred debits and other assets	**1,247,010**	1,148,412
Total assets	**$ 8,347,406**	$ 8,176,728
Capitalization and liabilities		
Capitalization *(see consolidated schedules of capitalization)*		
Common stock equity	**$ 2,949,305**	$ 2,818,807
Preferred stock - redemption not required	**59,376**	59,376
Long-term debt, net	**2,614,414**	2,415,656
Total capitalization	**5,623,095**	5,293,839
Current liabilities		
Current portion of long-term debt	**53,172**	207,979
Accounts payable	**265,163**	246,352
Interest accrued	**39,941**	43,620
Dividends declared	**74,400**	72,266
Other current liabilities	**108,824**	116,609
Total current liabilities	**541,500**	686,826
Deferred credits and other liabilities		
Accumulated deferred income taxes	**1,678,924**	1,722,908
Accumulated deferred investment tax credits	**211,822**	222,028
Other liabilities and deferred credits	**292,065**	251,127
Total deferred credits and other liabilities	**2,182,811**	2,196,063
Commitments and contingencies (Note 12)		
Total capitalization and liabilities	**$ 8,347,406**	$ 8,176,728

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS of CASH FLOWS

(In thousands)	**1998**	1997	1996
	Years ended December 31		
Operating activities			
Net income	**$399,238**	$388,317	$391,277
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**578,348**	565,212	446,508
Harris Plant deferred costs	**3,704**	19,670	19,416
Deferred income taxes	**(38,517)**	(66,546)	130,818
Investment tax credit	**(10,205)**	(10,232)	(10,445)
Deferred fuel credit	**(22,017)**	(24,969)	(23,156)
Net increase in receivables, inventories and prepaid expenses	**(62,351)**	(111,216)	(64,793)
Net increase (decrease) in payables and accrued expenses	**15,863**	(6,414)	4,671
Miscellaneous	**56,329**	59,191	17,911
Net cash provided by operating activities	**920,392**	813,013	912,207
Investing activities			
Gross property additions	**(424,263)**	(322,205)	(369,308)
Nuclear fuel additions	**(102,511)**	(61,509)	(87,265)
Contributions to nuclear decommissioning trust	**(30,848)**	(30,726)	(30,683)
Contributions to retiree benefit trusts	**-**	(21,096)	(24,700)
Net cash flow of company-owned life insurance program	**(1,954)**	138,508	46,930
Investments in non-electric activities	**(103,543)**	(54,733)	(28,035)
Net cash used in investing activities	**(663,119)**	(351,761)	(493,061)
Financing activities			
Proceeds from issuance of long-term debt	**6,255**	199,075	-
Net decrease in short-term debt (maturity less than 90 days)	**-**	(62,224)	(8,858)
Net increase (decrease) in commercial paper classified as long-term debt (Note 4)	**242,100**	(104,100)	350,000
Retirement of long-term debt	**(208,050)**	(103,410)	(467,810)
Redemption of preferred stock	**-**	(85,850)	-
Purchase of Company common stock	**-**	(23,418)	(25,208)
Dividends paid on common and preferred stock	**(282,684)**	(277,840)	(270,818)
Miscellaneous	**(448)**	-	-
Net cash used in financing activities	**(242,827)**	(457,767)	(422,694)
Net increase (decrease) in cash and cash equivalents	**14,446**	3,485	(3,548)
Cash and cash equivalents at beginning of year	**14,426**	10,941	14,489
Cash and cash equivalents at end of year	**$ 28,872**	$ 14,426	$ 10,941
Supplemental disclosures of cash flow information			
Cash paid during the year - interest	**$179,526**	$171,511	$194,391
income taxes	**$329,739**	$289,693	$141,350

See notes to consolidated financial statements.

CONSOLIDATED SCHEDULES of CAPITALIZATION

(Dollars in thousands except per share data)	*December 31* 1998	1997
Common stock equity		
Common stock without par value, authorized 200,000,000 shares, issued and outstanding 151,337,503 and 151,340,394 shares, respectively (Note 8)	**$1,374,773**	$1,371,520
Unearned ESOP common stock	**(152,979)**	(165,804)
Capital stock issuance expense	**(790)**	(790)
Retained earnings (Note 6)	**1,728,301**	1,613,881
Total common stock equity	**$2,949,305**	$2,818,807
Cumulative preferred stock, without par value (entitled to $100 a share plus accumulated dividends in the event of liquidation; outstanding shares are as of December 31, 1998)		
Preferred stock - redemption not required:		
Authorized - 300,000 shares $5.00 Preferred Stock; 20,000,000 shares Serial Preferred Stock		
$5.00 Preferred - 237,259 shares outstanding (redemption price $110.00)	**$ 24,376**	$ 24,376
4.20 Serial Preferred - 100,000 shares outstanding (redemption price $102.00)	**10,000**	10,000
5.44 Serial Preferred - 250,000 shares outstanding (redemption price $101.00)	**25,000**	25,000
Total preferred stock - redemption not required	**$59,376**	$59,376
Long-term debt (interest rates are as of December 31, 1998)		
First mortgage bonds:		
5.375% and 6.875% due 1998	**$ -**	$ 140,000
6.125% due 2000	**150,000**	150,000
6.75% due 2002	**100,000**	100,000
5.875% and 7.875% due 2004	**300,000**	300,000
6.80% due 2007	**200,000**	200,000
6.875% to 8.625% due 2021-2023	**500,000**	500,000
First mortgage bonds - secured medium-term notes:		
5.00% to 5.06% due 1998	**-**	65,000
7.15% due 1999	**50,000**	50,000
First mortgage bonds - pollution control series:		
6.30% to 6.90% due 2009-2014	**93,530**	93,530
3.399% and 3.55% due 2024	**122,600**	122,600
Total first mortgage bonds	**1,516,130**	1,721,130
Other long-term debt:		
Pollution control obligations backed by letter of credit, 2.982% to 5.350% due 2014-2017	**442,000**	442,000
Other pollution control obligations, 4.10% due 2019	**55,640**	55,640
Unsecured subordinated debentures, 8.55% due 2025	**125,000**	125,000
Commercial paper reclassified to long-term debt (Note 4)	**488,000**	245,900
Miscellaneous notes	**56,691**	53,486
Total other long-term debt	**1,167,331**	922,026
Unamortized premium and discount, net	**(15,875)**	(19,521)
Current portion of long-term debt	**(53,172)**	(207,979)
Total long-term debt, net	**$ 2,614,414**	$2,415,656
Total capitalization	**$5,623,095**	$5,293,839

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS of RETAINED EARNINGS

(In thousands except per share data)	**1998**	1997	1996
	Years ended December 31		
Retained earnings at beginning of year	**$ 1,613,881**	$1,503,658	$1,385,378
Net income	**399,238**	388,317	391,277
Preferred stock dividends at stated rates	**(2,967)**	(4,627)	(9,609)
Common stock dividends at annual per share rate of $1.955, $1.895 and $1.835, respectively	**(281,851)**	(272,011)	(263,388)
Other adjustments	**-**	(1,456)	-
Retained earnings at end of year	**$1,728,301**	$1,613,881	$1,503,658

CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

(In thousands except per share data)	*First Quarter*	*Second Quarter*	*Third Quarter*	*Fourth Quarter*
Year ended December 31, 1998				
Operating revenues	**$752,296**	**$736,151**	**$946,188**	**$695,410**
Operating income	**207,688**	**171,734**	**363,088**	**155,001**
Net income	**86,571**	**65,469**	**186,024**	**61,174**
Common stock data:				
Basic earnings per common share	**.60**	**.45**	**1.29**	**.42**
Diluted earnings per common share	**.60**	**.45**	**1.28**	**.42**
Dividend paid per common share	**.485**	**.485**	**.485**	**.485**
Price per share - high	**45¾**	**45½**	**46 5/8**	**49 1/16**
low	**40 5/8**	**39½**	**39 15/16**	**45 1/16**
Year ended December 31, 1997				
Operating revenues	$716,084	$666,023	$906,841	$735,141
Operating income	183,791	108,824	326,494	176,526
Net income	82,262	54,289	167,829	83,937
Common stock data:				
Basic and diluted earnings per common share	.56	.37	1.15	.58
Dividend paid per common share	.470	.470	.470	.470
Price per share - high	37 7/8	36¼	36 5/8	42 1/2
low	36 1/8	33	33 3/4	34 5/16

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Presentation

a. Organization

Carolina Power & Light Company (the Company) is a public service corporation primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. The Company has no other material segments of business. At December 31, 1998 and 1997, the total assets of the Company's non-electric segments were $210 million and $97 million, respectively. Revenues from external customers for the non-electric segments were $62 million, $19 million and $4 million for 1998, 1997 and 1996, respectively; those revenues are included in the results reported as diversified business operations.

b. Basis of Presentation

The consolidated financial statements are prepared in accordance with generally accepted accounting principles. The accounting records of the Company are maintained in accordance with uniform systems of accounts prescribed by the Federal Energy Regulatory Commission, the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). Certain amounts for 1997 and 1996 have been reclassified to conform to the 1998 presentation, with no effect on previously reported net income or common stock equity.

2. NCNG Merger

On November 10, 1998, the Company and North Carolina Natural Gas Corporation (NCNG) entered into an Agreement and Plan of Merger (Merger Agreement), providing for the strategic business combination of the Company and NCNG in a stock-for-stock transaction. Upon consummation of the proposed merger, NCNG will be a wholly owned subsidiary of the Company. The Company will issue approximately $354 million in stock to NCNG shareholders to complete the merger. The merger transaction is intended to constitute a tax-free reorganization for federal income tax purposes and to be accounted for as a pooling-of-interests. The Merger Agreement has been approved by the Boards of Directors of the Company and NCNG and consummation of the merger is expected in mid-1999. There are certain closing conditions, including approval by the shareholders of NCNG and certain regulatory agencies, and the filing of notifications required by the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The Company and NCNG filed a joint application for approval of the merger with the NCUC on January 11, 1999. The Company filed a similar request with the SCPSC on February 9, 1999.

3. Summary of Significant Accounting Policies

a. Principles of Consolidation

The consolidated financial statements include the activities of the Company and its majority-owned subsidiaries. These subsidiaries have invested in areas such as communications technology, energy-management services and affordable housing. Significant intercompany balances and transactions have been eliminated.

b. Use of Estimates and Assumptions

In preparing financial statements that conform with generally accepted accounting principles, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

c. Electric Utility Plant

The cost of additions, including betterments and replacements of units of property, is charged to electric 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, renewed or retired, plus removal or disposal costs, less salvage, is charged to accumulated depreciation. Generally, electric utility plant other than nuclear fuel is subject to the lien of the Company's mortgage.

The balances of electric utility plant in service at December 31 are listed below (in millions):

	1998	1997
Production plant	$ 6,295	$ 6,297
Transmission plant	987	952
Distribution plant	2,470	2,327
General plant and other	529	537
Electric utility plant in service	$10,281	$10,113

As prescribed in regulatory uniform systems of accounts, an allowance for the cost of borrowed and equity funds used to finance electric utility plant construction (AFUDC) is charged to the cost of plant. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the Company's utility rates to customers over the service life of the property. The equity funds portion of AFUDC is credited to other income and the borrowed funds portion is credited to interest charges. The composite AFUDC rate was 5.6% in both 1998 and 1997, and 5.8% in 1996.

d. Depreciation and Amortization

For financial reporting purposes, depreciation of electric utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated net salvage. Depreciation provisions, including decommissioning costs (see Note 3e), as a percent of average depreciable property other than nuclear fuel, were approximately 3.9% in 1998, 1997 and 1996. Depreciation provisions totaled $394.4 million, $382.1 million and $363.2 million in 1998, 1997 and 1996, respectively.

Depreciation and amortization expense also includes amortization of deferred operation and maintenance expenses associated with Hurricane Fran, which struck significant portions of the Company's service territory in September 1996. In 1996, the NCUC authorized the Company to defer these expenses (approximately $40 million) with amortization over a 40-month period.

Pursuant to authorizations from the NCUC and the SCPSC, the Company began to accelerate the amortization of certain regulatory assets over a three-year period beginning January 1997. The accelerated amortization of these regulatory assets results in additional depreciation and amortization expenses of approximately $68 million in each year of the three-year period. Depreciation and amortization expense also includes amortization of plant abandonment costs (see Note 7c).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE), is computed primarily on the unit-of-production method and charged to fuel expense. Costs related to obligations to the DOE for the decommissioning and decontamination of enrichment facilities are also charged to fuel expense.

e. Nuclear Decommissioning

In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC and the SCPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdiction, the provisions for nuclear decommissioning costs are based on amounts agreed upon in applicable rate agreements. Decommissioning cost provisions, which are included in depreciation and amortization expense, were $33.3 million, $33.2 million and $33.1 million in 1998, 1997 and 1996, respectively.

Accumulated decommissioning costs, which are included in accumulated depreciation, were $496.3 million and $428.7 million at December 31, 1998 and 1997, respectively. These costs include amounts retained internally and amounts funded in an external decommissioning trust. The balance of the nuclear decommissioning trust was $310.7 million and $245.5 million at December 31, 1998 and 1997, respectively. Trust earnings increase the trust balance with a corresponding increase in the accumulated decommissioning balance. These balances are adjusted for net unrealized gains and losses related to changes in the fair value of trust assets. Based on the site-specific estimates discussed below, and using an assumed after-tax earnings rate of 7.75% and an assumed cost escalation rate of 4%, current levels of rate recovery for nuclear decommissioning costs are adequate to provide for decommissioning of the Company's nuclear facilities.

The Company's most recent site-specific estimates of decommissioning costs were developed in 1998, using 1998 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring shortly after operating license expiration. These estimates, in 1998 dollars, are $279.8 million for Robinson Unit No. 2, $299.3 million for Brunswick Unit No. 1, $298.5 million for Brunswick Unit No. 2 and $328.1 million for the Harris Plant. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in the Brunswick and Harris nuclear generating facilities. Operating licenses for the Company's nuclear units expire in the year 2010 for Robinson Unit No. 2, 2016 for Brunswick Unit No. 1, 2014 for Brunswick Unit No. 2 and 2026 for the Harris Plant.

The Financial Accounting Standards Board is proceeding with its project regarding accounting practices related to obligations associated with the retirement of long-lived assets, and an exposure draft of a proposed accounting standard is expected to be issued during the first half of 1999. It is uncertain when a final statement will be issued and what effects it may ultimately have on the Company's accounting for nuclear decommissioning and other retirement costs.

f. Other Policies

Customers' meters are read and bills are rendered on a cycle basis. Revenues are accrued for services rendered but unbilled at the end of each accounting period.

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the Company's regulators. These clauses allow the Company to recover fuel costs and the fuel component of purchased power costs through the fuel component of customer rates.

Other property and investments are stated principally at cost. The Company maintains an allowance for doubtful accounts receivable, which totaled approximately $13.8 million and $3.4 million at December 31, 1998 and 1997, respectively. Fuel inventory and materials and supplies inventory are carried on a first-in, first-out or average cost basis. Long-term debt premiums, discounts and issuance expenses are amortized over the life of the related debt using the straight-line method. Any expenses or call premiums associated with the reacquisition of debt obligations are amortized over the remaining life of the original debt using the straight-line method, except that the balance existing at December 31, 1996 is being amortized on a three-year accelerated basis (see Note 7a). The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

g. New Accounting Standard

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS-133), effective for fiscal years beginning after June 15, 1999. SFAS-133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recognition of all derivative instruments as assets or liabilities in the statement of financial position and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not an instrument qualifies as a hedge and, if so, the type of hedge. The Company has not completed its analysis of the provisions of SFAS-133 nor its effect on the Company.

4. Revolving Credit Facilities and Commercial Paper

As of December 31, 1998, the Company's revolving credit facilities totaled $750 million, all of which are long-term agreements supporting its commercial paper borrowings. The Company is required to pay minimal annual commitment fees to maintain its credit facilities. Consistent with management's intent to maintain its commercial paper on a long-term basis, and as supported by its long-term revolving credit facilities, the Company included in long-term debt all commercial paper outstanding as of December 31, 1998 and 1997, which amounted to $488.0 million and $245.9 million, respectively. The weighted-average interest rates of these borrowings were 5.22% and 5.85% at December 31, 1998 and 1997, respectively.

5. Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents approximate fair value due to the short maturities of these instruments. At December 31, 1998 and 1997, there were miscellaneous investments with carrying amounts of approximately $12 million and $9 million, respectively, included in miscellaneous other property and investments. The carrying amounts of these investments approximate fair value due to the short maturities of the related instruments. The carrying amount of the Company's long-term debt was $2.70 billion and $2.66 billion at December 31, 1998 and 1997, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2.80 billion and $2.71 billion at December 31, 1998 and 1997, respectively.

External funds have been established, as required by the Nuclear Regulatory Commission (NRC), as a mechanism to fund certain costs of nuclear decommissioning (see Note 3e). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. Nuclear decommissioning trust funds are presented at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments.

6. Capitalization

As of December 31, 1998, the Company had 20,656,571 shares of authorized but unissued common stock reserved and available for issuance, primarily to satisfy the requirements of the Company's stock plans. The Company intends, however, to meet the requirements of these stock plans with issued and outstanding shares presently held by the Trustee of the Stock Purchase-Savings Plan or with open market purchases of common stock shares, as appropriate. In addition, the Company's Board of Directors has authorized the issuance of shares in conjunction with the planned merger with NCNG (see Note 2).

The Company's mortgage, as supplemented, and charter contain provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. As of December 31, 1998, there were no significant restrictions on the use of retained earnings.

As of December 31, 1998, long-term debt maturities for the years 1999, 2000, 2002 and 2003 amounted to $53 million, $198 million, $100 million and $5 million, respectively, excluding commercial paper reclassified as long-term debt. There are no long-term debt maturities in 2001.

7. Regulatory Matters

a. Regulatory Assets

As a regulated entity, the Company is subject to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," (SFAS-71). See Note 12c for additional discussion of SFAS-71. Accordingly, the Company records certain assets resulting from the effects of the ratemaking process, which would not be recorded under generally accepted accounting principles for unregulated entities. At December 31, 1998, the balances of the Company's regulatory assets were as follows (in millions):

Income taxes recoverable through future rates*	$ 278
Harris Plant deferred costs	60
Abandonment costs*	16
Loss on reacquired debt (included in unamortized debt expense)*	21
Deferred fuel	43
Items included in other assets and deferred debits:	
Deferred DOE enrichment facilities-related costs	46
Deferred hurricane-related costs	12
Emission allowance carrying costs*	4
Total	$ 480

* *All or certain portions of these regulatory assets are subject to accelerated amortization (see Note 3d).*

b. Retail Rate Matters

A petition was filed in July 1996 by the Carolina Industrial Group for Fair Utility Rates (CIGFUR) with the NCUC, requesting that the NCUC conduct an investigation of the Company's base rates or treat its petition as a complaint against the Company. The petition alleged that the Company's return on equity (which was authorized by the NCUC in the Company's last general rate proceeding in 1988) and earnings are too high. In December 1996, the NCUC issued an order denying CIGFUR's petition and stating that it tentatively found no reasonable grounds to proceed with CIGFUR's petition as a complaint. Subsequently, CIGFUR filed a Motion for Reconsideration with the NCUC and a Notice of Appeal with the North Carolina Court of Appeals, both of which were denied. On December 4, 1998, a petition for Discretionary Review filed by CIGFUR was denied by the North Carolina Supreme Court.

In late 1998 and early 1999, the Company filed, and the respective commissions subsequently approved, proposals in the North and South Carolina retail jurisdictions to accelerate cost recovery of its nuclear generating assets beginning January 1, 2000 and continuing through 2004. The accelerated cost recovery begins immediately after the 1999 expiration of the accelerated amortization of certain regulatory assets (see Note 3d). Pursuant to the orders, the Company's depreciation expense for nuclear generating assets will increase by $106 million to $150 million per year. Recovering the costs of the nuclear generating assets on an accelerated basis will better position the Company for the uncertainties associated with potential restructuring of the of the electric utility industry.

c. Plant-Related Deferred Costs

The Company abandoned efforts to complete Mayo Unit No. 2 in March 1987. The NCUC and SCPSC each allowed the Company to recover the cost of the abandoned unit over a ten-year period without a return on the unamortized balance. The cost recovery was substantially completed during 1998.

In the 1988 rate orders, the Company was ordered to remove from rate base and treat as abandoned plant certain costs related to the Harris Plant. Abandoned plant amortization related to the 1988 rate orders was completed in 1998 for the wholesale and North Carolina retail jurisdictions and will be completed in 1999 for the South Carolina retail jurisdiction.

Amortization of plant abandonment costs is included in depreciation and amortization expense and totaled $24.2 million, $30.8 million and $17.6 million in 1998, 1997 and 1996, respectively. The unamortized balances of plant abandonment costs are reported at the present value of future recoveries of these costs. The associated accretion of the present value was $1.7 million, $3.5 million and $26.4 million in 1998, 1997 and 1996, respectively, and is reported in other, net. The accretion for 1996 includes a $22.9 million adjustment to the unamortized balance of plant abandonment costs related to the Harris Plant. This adjustment was made to reflect the present value impact of the shorter recovery period resulting from accelerated amortization of this asset (see Note 3d).

8. Employee Stock Ownership Plan

The Company sponsors the Stock Purchase-Savings Plan (SPSP) for which substantially all full-time employees and certain part-time employees are eligible. The SPSP, which has Company matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Company common stock and other diverse investments. The SPSP, as amended in 1989, is an employee stock ownership plan (ESOP) that can enter into acquisition loans to acquire Company common stock to satisfy SPSP common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the SPSP. Common stock acquired with the proceeds of an ESOP loan is held by the SPSP Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to participant contributions, Company matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. To the extent used to repay such loans, the dividends are deductible for income tax purposes.

There were 6,953,612 ESOP suspense shares at December 31, 1998, with a fair value of $327.3 million. ESOP shares allocated to plan participants totaled 12,416,040 at December 31, 1998. The Company has a long-term note receivable from the SPSP Trustee related to the purchase of common stock from the Company in 1989. The balance of the note receivable from the SPSP Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

9. Postretirement Benefit Plans

The Company has a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees.

The components of net periodic pension cost are (in thousands):

	1998	1997	1996
Actual return on plan assets	$ (87,382)	$ (110,346)	$ (76,347)
Variance from expected return, deferred	17,462	57,368	27,056
Expected return on plan assets	(69,920)	(52,978)	(49,291)
Service cost	18,357	18,643	19,257
Interest cost	45,877	42,468	39,505
Amortization of transition obligation	106	106	106
Amortization of prior service cost (benefit)	(158)	967	724
Amortization of actuarial gain	(6,440)	(36)	(364)
Net periodic pension cost (benefit)	$ (12,178)	$ 9,170	$ 9,937

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period

of active participants. Actuarial gains and losses in excess of 10% of the greater of the pension obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

Reconciliations of the changes in the plan's benefit obligations and the plan's funded status are (in thousands):

	1998	1997
Pension obligation		
Pension obligation at January 1	$ 598,160	$ 558,688
Interest cost	45,877	42,468
Service cost	18,357	18,643
Benefit payments	(25,466)	(25,557)
Actuarial loss	77,785	3,918
Plan amendments	(36,503)	-
Pension obligation at December 31	678,210	598,160
Fair value of plan assets at December 31	830,213	768,297
Funded status	152,003	170,137
Unrecognized transition obligation	688	793
Unrecognized prior service cost (benefit)	(25,429)	10,916
Unrecognized actuarial gain	(145,657)	(212,419)
Accrued pension obligation at December 31	$ (18,395)	$ (30,573)

Reconciliations of the fair value of pension plan assets are (in thousands):

	1998	1997
Fair value of plan assets at January 1	$ 768,297	$ 683,508
Actual return on plan assets	87,382	110,346
Benefit payments	(25,466)	(25,557)
Fair value of plan assets at December 31	$ 830,213	$ 768,297

The weighted-average discount rate used to measure the pension obligation was 7.0% in 1998 and 7.75% in 1997. The assumed rate of increase in future compensation used to measure the pension obligation was 4.20% in both 1998 and 1997. The expected long-term rate of return on pension plan assets used in determining the net periodic pension cost was 9.25% in 1998, 1997 and 1996.

In addition to pension benefits, the Company provides contributory postretirement benefits (OPEB), including certain health care and life insurance benefits, for substantially all retired employees.

The components of net periodic OPEB cost are (in thousands):

	1998	1997	1996
Actual return on plan assets	$ (3,877)	$ (4,628)	$ (2,656)
Variance from expected return, deferred	785	2,186	726
Expected return on plan assets	(3,092)	(2,442)	(1,930)
Service cost	7,182	7,988	8,412
Interest cost	13,402	11,065	10,629
Amortization of transition obligation	5,641	5,889	5,889
Amortization of actuarial gain	(549)	-	-
Net periodic OPEB cost	$ 22,584	$ 22,500	$ 23,000

Actuarial gains and losses in excess of 10% of the greater of the OPEB obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

Reconciliations of the changes in the plan's benefit obligations and the plan's funded status are (in thousands):

	1998	1997
OPEB obligation		
OPEB obligation at January 1	$ 181,324	$164,487
Interest cost	13,402	11,065
Service cost	7,182	7,988
Benefit payments	(4,774)	(5,235)
Actuarial loss	3,428	3,019
Plan amendment	(3,716)	-
OPEB obligation at December 31	196,846	181,324
Fair value of plan assets at December 31	37,304	33,427
Funded status	(159,542)	(147,897)
Unrecognized transition obligation	78,978	88,336
Unrecognized actuarial gain	(7,314)	(10,506)
Accrued OPEB obligation at December 31	$ (87,878)	$ (70,067)

Reconciliations of the fair value of OPEB plan assets are (in thousands):

	1998	1997
Fair value of plan assets at January 1	$ 33,427	$ 28,799
Actual return on plan assets	3,877	4,628
Fair value of plan assets at December 31	$ 37,304	$ 33,427

The assumptions used to measure the OPEB obligation are:

	1998	1997
Weighted-average discount rate	7.00%	7.75%
Initial medical cost trend rate for pre-Medicare benefits	6.60%	7.20%
Initial medical cost trend rate for post-Medicare benefits	6.40%	7.00%
Ultimate medical cost trend rate	4.50%	5.25%
Year ultimate medical cost trend rate is achieved	2006	2005

The expected long-term rate of return on plan assets used in determining the net periodic OPEB cost was 9.25% in 1998, 1997 and 1996. The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 1998 would increase by $3.3 million, and the OPEB obligation at December 31, 1998 would increase by $24.8 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 1998 would decrease by $2.7 million and the OPEB obligation at December 31, 1998 would decrease by $21.2 million.

10. Income Taxes

Deferred income taxes are provided for temporary differences between book and tax bases of assets and liabilities. Investment tax credits related to operating income are amortized over the service life of the related property.

Net accumulated deferred income tax liabilities at December 31 are (in thousands):

	1998	1997
Accelerated depreciation and property cost differences	$ 1,632,119	$ 1,676,505
Deferred costs, net	66,757	87,829
Miscellaneous other temporary differences, net	10,885	300
Net accumulated deferred income tax liability	$ 1,709,761	$ 1,764,634

Total deferred income tax liabilities were $2.21 billion and $2.24 billion at December 31, 1998 and 1997, respectively. Total deferred income tax assets were $501 million and $472 million at December 31, 1998 and 1997, respectively.

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

	1998	1997	1996
Effective income tax rate	39.2%	37.5%	39.5%
State income taxes, net of federal income tax benefit	(4.7)	(4.9)	(4.9)
Investment tax credit amortization	1.5	1.7	1.6
Other differences, net	(1.0)	0.7	(1.2)
Statutory federal income tax rate	35.0%	35.0%	35.0%

The provisions for income tax expense are comprised of (in thousands):

	1998	1997	1996
Income tax expense (credit)			
Current - federal	$ 254,400	$ 258,050	$ 110,188
state	51,817	56,747	25,355
Deferred - federal	(34,842)	(61,384)	107,589
state	(3,675)	(9,465)	23,229
Investment tax credit	(10,206)	(10,232)	(10,445)
Total income tax expense	$ 257,494	$ 233,716	$ 255,916

11. Joint Ownership of Generating Facilities

Power Agency holds 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 of additional construction costs, fuel inventory purchases and operating expenses. The Company's share of expenses for the jointly owned units is included in the appropriate expense category.

The Company's ownership interest in the jointly owned generating facilities is listed below with related information as of December 31, 1998 (dollars in millions):

Facility	Megawatt Capability	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Under Construction
Mayo Plant	745	83.83%	$ 450	$ 193	$ 2
Harris Plant	860	83.83%	$ 2,997	$ 1,008	$ 48
Brunswick Plant	1631	81.67%	$ 1,414	$ 978	$ 3
Roxboro Unit No. 4	700	87.06%	$ 231	$ 110	$ 6

In the table above, plant investment and accumulated depreciation, which includes accumulated nuclear decommissioning, are not reduced by the regulatory disallowances related to the Harris Plant.

12. Commitments and Contingencies

a. Purchased Power

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between the Company and Power Agency, the Company is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant. In 1993, the Company and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, the Company increased the amount of capacity and energy purchased from Power Agency's ownership interest in the Harris Plant, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capital-related capacity costs, total approximately $26 million. These contractual purchases, including purchases from the Mayo Plant that ended in 1997, totaled $34.4 million, $36.2 million and $36.7 million for 1998, 1997 and 1996, respectively. In 1987, the NCUC ordered the Company to reflect the recovery of the capacity portion of these costs on a levelized basis over the original 15-year buyback period, thereby deferring for future recovery the difference between such costs and amounts collected through rates. In 1988, the SCPSC ordered similar treatment, but with a 10-year levelization period. At December 31, 1998 and 1997, the Company had deferred purchased capacity costs, including carrying costs accrued on the deferred balances, of $60.0 million and $63.7 million, respectively. Increased purchases (which are not being deferred for future recovery) resulting from the 1993 agreement with Power Agency were approximately $19 million, $17 million and $13 million for 1998, 1997 and 1996, respectively.

The Company has two long-term agreements for the purchase of power and related transmission services from other utilities. The first agreement provides for the purchase of 250 megawatts of capacity through 2009 from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The second agreement is with Duke Energy (Duke) for the purchase of 400 megawatts of firm capacity through mid-1999. The estimated minimum annual payments for power purchases under these agreements are approximately $31 million for Rockport and $48 million for Duke, representing capital-related capacity costs. Total purchases (including transmission use charges) under the Rockport agreement amounted to $59.3 million, $61.9 million and $60.9 million for 1998, 1997 and 1996, respectively. Total purchases (including transmission use charges) under the agreement with Duke amounted to $75.5 million, $69.5 million and $65.4 million for 1998, 1997 and 1996, respectively.

b. Insurance

The Company is a member of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, the Company is insured for $500 million at each of its nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.4 billion on the Brunswick Plant, $2 billion on the Harris Plant and $800 million on the Robinson Plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. The Company is insured thereunder for six weeks (beginning 17 weeks after the outage begins) in the amount of $3.5 million per week. For accidental outages extending beyond 23 weeks, the Company is covered for the next 52 weeks in weekly amounts of $1.85 million at Brunswick Unit No. 1, $1.83 million at Brunswick Unit No. 2, $1.9 million at the Harris Plant and $1.6 million at Robinson Unit No. 2. An additional 104 weeks of coverage is provided at 80% of the above weekly amounts. For the current policy period, the Company is subject to retrospective premium assessments of up to approximately $12.1 million with respect to the primary coverage, $17.5 million with respect to the decontamination, decommissioning and excess property coverage and $6.3 million for the incremental replacement power costs coverage in the event covered expenses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. These resources at present total approximately $3.9 billion. Pursuant to regulations of the NRC, the Company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontamination costs, before any proceeds can be used for decommissioning, plant repair or restoration. The Company is responsible to the extent losses may exceed limits of the coverage described above. Power Agency would be responsible for its ownership share of such losses and for certain retrospective premium assessments on jointly owned nuclear units.

The Company is insured against public liability for a nuclear incident up to $9.8 billion per occurrence, which is the maximum limit on public liability claims pursuant to the Price-Anderson Act. In the event that public liability claims from an insured nuclear incident exceed $200 million, the Company would be subject to a pro rata assessment of up to $83.9 million, plus a 5% surcharge, for each reactor owned for each incident. Payment of such assessment would be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. Power Agency would be responsible for its ownership share of the assessment on jointly owned nuclear units.

c. Applicability of SFAS-71

The Company's ability to continue to meet the criteria for application of SFAS-71 (see Note 7a) may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS-71 no longer applied to a separable portion of the Company's operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment of electric utility plant assets as determined pursuant to Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of".

d. Claims and Uncertainties

1. The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters.

   Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under various federal and state laws. There are several manufactured gas plant (MGP) sites to which the Company and certain entities that were later merged into the Company had some connection. In this regard, the Company, along with others, is participating in a cooperative effort with the North Carolina Department of Environment and Natural Resources, Division of Waste Management (DWM), which has established a uniform framework to address MGP sites. The investigation and remediation of specific MGP sites will be addressed pursuant to one or more Administrative Orders on Consent (AOC) between the DWM and the potentially responsible party or parties. The Company has signed AOCs to investigate certain sites. The Company continues to investigate the identities of parties connected to individual MGP sites, the relative relationships of the Company and other parties to those sites and the degree to which the Company will undertake efforts with others at individual sites. The Company does not expect the costs associated with these sites to be material to the financial position and results of operations of the Company.

   The Company has been notified by regulators of its involvement or potential involvement in several sites, other than MGP sites, that may require investigation and/or remediation. Although the Company may incur costs at these sites, the investigation and/or remediation of the sites has not advanced to a stage where reasonable cost estimates can be made. The Company cannot predict the outcome of these matters.

   The Company carries a liability for the estimated costs associated with certain remedial activities. This liability is not material to the financial position of the Company.

2. As required under the Nuclear Waste Policy Act of 1982, the Company entered into a contract with the U.S. Department of Energy (DOE) under which the DOE agreed to begin taking spent nuclear fuel by January 31, 1998. The DOE defaulted on its January 31, 1998 obligation to begin taking spent nuclear fuel, and a group of utilities, including the Company, has undertaken measures to force the DOE to take spent nuclear fuel. To date, the courts have rejected these attempts. In addition, several utilities have filed actions for damages in the United States Court of Claims, and in some of those cases the Court has agreed that the DOE has breached its contract for disposal of spent nuclear fuel. The Company is in the process of evaluating whether it should file a similar action for damages. The Company will also monitor legislation that has been introduced in Congress that would provide for interim storage of spent nuclear fuel at a storage facility operated by the DOE. The Company cannot predict the outcome of this matter.

   With certain modifications and additional approval by the NRC, the Company's spent nuclear fuel storage facilities

will be sufficient to provide storage space for spent fuel generated on the Company's system through the expiration of the current operating licenses for all of the Company's nuclear generating units. Subsequent to the expiration of these licenses, dry storage may be necessary. The Company has initiated the process of obtaining the additional NRC approval.

3. In the opinion of management, liabilities, if any, arising under other pending claims would not have a material effect on the financial position and results of operations of the Company.

CAROLINA POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Year Ended December 31, 1998

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
Description	Balance at Beginning of Period	(1) Charged to Income	(2) Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves deducted from related assets on the balance sheet: Uncollectible accounts	$ 3,366,361	$ 17,993,081	$ -0-	$ 7,132,511	$ 14,226,931
Reserves deducted from related assets on the balance sheet: Inventory	$ -0-	$ 145,051	$ -0-	$ -0-	$ 145,051
Reserves other than those deducted from assets on the balance sheet: Injuries and damages	$ 1,319,664	$ 806,828	$ -0-	$ 1,115,936	$ 1,010,556
Reserve for possible coal mine investment losses	$ 7,505,994	$ -0-	$ -0-	$ 177,529	$ 7,328,465
Reserve for employee retirement and compensation plans	$ 142,232,971	$ 16,569,740	$ -0-	$ 7,327,455	$ 151,475,256
Reserve for environmental investigation and remediation costs	$ 1,815,909	$ -0-	$ -0-	$ 1,494,461	$ 321,448
Reserve for product warranty	$ -0-	$ 465,000	$ -0-	$ -0-	$ 465,000

CAROLINA POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Year Ended December 31, 1997

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
Description	Balance at Beginning of Period	(1) Charged to Income	(2) Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts	$ 3,689,783	$ 6,296,392	$ -0-	$ 6,619,814	$ 3,366,361
Reserves other than those deducted from assets on the balance sheet:					
Injuries and damages	$ 1,277,888	$ 714,353	$ -0-	$ 672,577	$ 1,319,664
Reserve for possible coal mine investment losses	$ 7,625,008	$ -0-	$ -0-	$ 119,014	$ 7,505,994
Reserve for employee retirement and compensation plans	$ 107,569,407	$ 39,690,015	$ -0-	$ 5,026,451	$ 142,232,971
Reserve for environmental investigation and remediation costs	$ 1,815,909	$ -0-	$ -0-	$ -0-	$ 1,815,909

CAROLINA POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Year Ended December 31, 1996

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
Description	Balance at Beginning of Period	(1) Charged to Income	(2) Charged to Other Accounts	Deductions from Reserves	Balance at Close of Period
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts	$ 2,323,808	$ 8,525,513	$ -0-	$ 7,159,538	$ 3,689,783
Reserves other than those deducted from assets on the balance sheet:					
Injuries and damages	$ 1,270,881	$ 1,033,504	$ -0-	$ 1,026,497	$ 1,277,888
Reserve for possible coal mine investment losses	$ 7,797,250	$ -0-	$ -0-	$ 172,242	$ 7,625,008
Reserve for employee retirement and compensation plans	$ 91,779,866	$ 41,816,846	$ -0-	$ 26,027,305	$ 107,569,407
Reserve for environmental investigation and remediation costs	$ 1,906,730	$ -0-	$ -0-	$ 90,821	$ 1,815,909

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

NONE

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 1999 definitive proxy statement dated April 1, 1999, and incorporated by reference herein.

b) Information on the Company's executive officers is set forth in Part I and incorporated by reference herein.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in the Company's 1999 definitive proxy statement dated April 1, 1999, and incorporated by reference herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

a) The Company knows of no person who is a beneficial owner of more than five (5%) 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 1999 definitive proxy statement dated April 1, 1999, and incorporated by reference herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on certain relationships and related transactions is set forth in the Company's 1999 definitive proxy statement dated April 1, 1999, and incorporated by reference herein.

PART IV

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

a) The following documents are filed as part of the report:

1. Consolidated Financial Statements Filed:
   See ITEM 8 - Consolidated Financial Statements and Supplementary Data.

2. Consolidated Financial Statement Schedules Filed:
   See ITEM 8 - Consolidated Financial Statements and Supplementary Data

3. Exhibits Filed:
See EXHIBIT INDEX

b) Reports on Form 8-K filed during or with respect to the last quarter of 1998 and the portion of the first quarter of 1999 prior to the filing of this Form 10-K:

1. Current Report on Form 8-K dated February 26, 1999.

2. Current Report on Form 8-K dated March 19, 1999.

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.

Date: 3/25/99

CAROLINA POWER & LIGHT COMPANY
(Registrant)
By: /s/ Glenn E. Harder
Executive Vice President, Chief Financial Officer and
Principal Accounting Officer

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/ William Cavanaugh III (William Cavanaugh III, President and Chief Executive Officer)	Principal Executive Officer and Director	3/17/99
/s/ Glenn E. Harder (Glenn E. Harder Executive Vice President, Chief Financial Officer and Principal Accounting Officer)	Principal Financial Officer	3/17/99
/s/ Sherwood H. Smith, Jr. (Sherwood H. Smith, Jr., Chairman)	Director	3/17/99
/s/ Leslie M. Baker, Jr. (Leslie M. Baker, Jr.)	Director	3/17/99
/s/ Edwin B. Borden (Edwin B. Borden)	Director	3/17/99

/s/ Charles W. Coker (Charles W. Coker)	Director	3/17/99
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	3/17/99
/s/ Walter Y. Elisha (Walter Y. Elisha)	Director	3/17/99
/s/ Robert L. Jones (Robert L. Jones)	Director	3/17/99
/s/ Estell C. Lee (Estell C. Lee)	Director	3/17/99
/s/ William O. McCoy (William O. McCoy)	Director	3/17/99
/s/ John H. Mullin, III (John H. Mullin, III)	Director	3/17/99
/s/ J. Tylee Wilson (J. Tylee Wilson)	Director	3/17/99

EXHIBIT INDEX

Exhibit Number	Description
*2	Agreement and Plan of Merger By and Among Carolina Power & Light Company, North Carolina Natural Gas Corporation and Carolina Acquisition Corporation, dated as of November 10, 1998 (filed as Exhibit No. 2(b) to quarterly report on Form 10-Q for the quarterly period ended September 30, 1998, File No. 1-3382.)
*3a(1)	Restated Charter of Carolina Power & Light Company, as amended May 10, 1996 (filed as Exhibit No. 3(i) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1995, File No. 1-3382).
*3a(2)	Restated Charter of Carolina Power & Light Company as amended on May 10, 1996 (filed as Exhibit 3(i) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-3382).
*3b(1)	By-Laws of Carolina Power & Light Company, as amended May 10, 1996 (filed as Exhibit No. 3(ii) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1995, File No. 1-3382).
*3b(2)	By-Laws of Carolina Power & Light Company, as amended on September 18, 1996 (filed as Exhibit 3(ii) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1997, File No.1-3382).
3b(3)	By-Laws of Carolina Power & Light Company, as amended on March 17, 1999.
*4a(1)	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 3(c), File No. 33-25560).
*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 3(d), File No. 33-25560).
*4a(3)	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 3(f), File No. 33-25560).
*4a(4)	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 3(g), File No. 33-25560).

*4b	Mortgage and Deed of Trust dated as of May 1, 1940 between the Company and The Bank of New York (formerly, Irving Trust Company) and Frederick G. Herbst (Douglas J. MacInnes, Successor), Trustees and the First through Fifth Supplemental Indentures thereto (Exhibit 2(b), File No. 2-64189); and the Sixth through Sixty-sixth 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. 2-22439; 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; Exhibits 2(c) and 2(d), File No. 2-66851; Exhibits 4(b)-1, 4(b)-2, and 4(b)-3, File No. 2-81299; Exhibits 4(c)-1 through 4(c)-8, File No. 2-95505; Exhibits 4(b) through 4(h), File No. 33-25560; Exhibits 4(b) and 4(c), File No. 33-33431; Exhibits 4(b) and 4(c), File No. 33-38298; Exhibits 4(h) and 4(i), File No. 33-42869; Exhibits 4(e)-(g), File No. 33-48607; Exhibits 4(e) and 4(f), File No. 33-55060; Exhibits 4(e) and 4(f), File No. 33-60014; Exhibits 4(a) and 4(b) to Post-Effective Amendment No. 1, File No. 33-38349; Exhibit 4(e), File No. 33-50597; Exhibit 4(e) and 4(f), File No. 33-57835; Exhibit to Current Report on Form 8-K dated August 28, 1997, File No. 1-3382; Form of Carolina Power & Light Company First Mortgage Bond, 6.80% Series Due August 15, 2007 filed as Exhibit 4 to Form 10-Q for the period ended September 30, 1998, File No. 1-3382; Exhibit 4(b), File No. 333-69237; and Exhibit 4(c), File No. 1-03382.)
*4c(1)	Indenture, dated as of March 1, 1995, between the Company and Bankers Trust Company, as Trustee, with respect to Unsecured Subordinated Debt Securities (filed as Exhibit No. 4(c) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).
*4c(2)	Resolutions adopted by the Executive Committee of the Board of Directors at a meeting held on April 13, 1995, establishing the terms of the 8.55% Quarterly Income Capital Securities (Series A Subordinated Deferrable Interest Debentures) (filed as Exhibit 4(b) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).
*4d	Indenture (for Senior Notes), dated as of March 1, 1999 between Carolina Power & Light Company and The Bank of New York as Trustee and the First Supplemental Senior Note Indenture thereto, (filed as Exhibits No. 4(a) and 4(b) to Current Report on Form 8-K dated March 19, 1999, File No. 1-03382).
*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), File No. 33-25560).

*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 16, 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 10(b), File No. 33-25560).
*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 10(c), File No. 33-25560).
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).
*10a(5)	Agreement Regarding New Resources and Interim Capacity between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency dated October 13, 1987 (filed as Exhibit 10(e), File No. 33-25560).
*10a(6)	Power Coordination Agreement - 1987A between North Carolina Eastern Municipal Power Agency and Carolina Power & Light Company for Contract Power From New Resources Period 1987-1993 dated October 13, 1987 (filed as Exhibit 10(f), File No. 33-25560).
+ *10b(1)	Directors Deferred Compensation Plan effective January 1, 1982 as amended (filed as Exhibit 10(g), File No. 33-25560).
+ *10b(2)	Supplemental Executive Retirement Plan effective January 1, 1984 (filed as Exhibit 10(h), File No. 33-25560).
+ *10b(3)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).
+ *10b(4)	Executive Deferred Compensation Plan effective May 1, 1982 as amended (filed as Exhibit 10(j), File No. 33-25560).
+ *10b(5)	Key Management Deferred Compensation Plan (filed as Exhibit 10(k), File No. 33-25560).
+ *10b(6)	Resolutions of the Board of Directors, dated March 15, 1989, amending the Key Management Deferred Compensation Plan (filed as Exhibit 10(a), File No. 33-48607).
+ *10b(7)	Resolutions of the Board of Directors dated May 8, 1991, amending the Directors Deferred Compensation Plan (filed as Exhibit 10(b), File No. 33-48607).

+*10b(8)	Resolutions of the Board of Directors dated May 8, 1991, amending the Executive Deferred Compensation Plan (filed as Exhibit 10(c), File No. 33-48607).
+*10b(9)	1997 Equity Incentive Plan, approved by the Company's shareholders May 7, 1997, effective as of January 1, 1997 (filed as Appendix A to the Company's 1997 Proxy Statement, File No. 1-03382).
+*10b(10)	Performance Share Sub-Plan of the 1997 Equity Incentive Plan, adopted by the Personnel, Executive Development and Compensation Committee of the Board of Directors, March 19, 1997, subject to shareholder approval of the 1997 Equity Incentive Plan, which was obtained on May 7, 1997, (filed as Exhibit 10(b), File No. 1-03382).
+*10b(11)	Resolutions of Board of Directors dated July 9, 1997, amending the Deferred Compensation Plan for Key Management Employees of Carolina Power & Light Company.
+*10b(12)	Resolutions of Board of Directors dated July 9, 1997, amending the Supplemental Executive Retirement Plan of Carolina Power & Light Company.
+*10b(13)	Amended Management Incentive Compensation Program of Carolina Power & Light Company, as amended December 10, 1997.
+*10b(14)	Carolina Power & Light Company Restoration Retirement Plan, effective January 1, 1998.
+*10b(15)	Carolina Power & Light Company Non-Employee Director Stock Unit Plan, effective January 1, 1998.
+*10b(16)	Carolina Power & Light Company Restricted Stock Agreement, as approved January 7, 1998, pursuant to the Company's 1997 Equity Incentive Plan (filed as Exhibit No. 10 to quarterly report on Form 10-Q for the quarterly period ended March 31, 1998, File No. 1-3382.)
+*10b(17)	Resolutions of Board of Directors dated July 17, 1998, amending the Supplemental Executive Retirement Plan of Carolina Power & Light Company, effective January 1, 1999, (filed as Exhibit No. 10(a) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1998, File No. 1-3382.)
+*10b(18)	Amended Management Incentive Compensation Plan of Carolina Power & Light Company, effective January 1, 1999, as amended by the Organization and Compensation Committee of the Board of Directors on July 17, 1998, (filed as Exhibit No. 10(b) to quarterly report on Form 10-Q for the quarterly period ended June 30, 1998, File No. 1-3382.)
+10b(19)	Supplemental Senior Executive Retirement Plan of Carolina Power & Light Company, as amended January 1, 1999.

+10b(20)	Carolina Power & Light Company Restoration Retirement Plan, as amended January 1, 1999.
+*10b(21)	Employment Agreement dated September 1, 1992, by and between the Company and William Cavanaugh III (filed as Exhibit 10b, File No. 1-03382).
+*10b(22)	Employment Agreement dated April 1, 1993, by and between the Company and William S. Orser (filed as Exhibit 10b, File No. 1-03382).
+*10b(23)	Employment Arrangement dated September 27, 1994 by and between the Company and Glenn E. Harder (filed as Exhibit 10b, File No. 1-03382).
+*10b(24)	Personal Services Agreement dated September 18, 1996, by and between the Company and Sherwood H. Smith, Jr. (filed as Exhibit 10b, File No.1-03382).
+*10b(25)	Employment Agreement dated June 2, 1997, by and between the Company and Robert B. McGehee (filed as Exhibit 10b, File No. 1-03382).
+*10b(26)	Employment Agreement dated September 24, 1997, by and between the Company and John E. Manczak (filed as Exhibit 10b, File No. 1-03382).
+10b(27)	Employment Agreement dated August 3, 1998, by and between the Company and Tom D. Kilgore.
12	Computation of Ratio of Earnings to Fixed Charges and Preferred Dividends Combined and Ratio of Earnings to Fixed Charges.
21	Subsidiaries of Carolina Power & Light Company
23(a)	Consent of Deloitte & Touche LLP.

*Incorporated herein by reference as indicated.
+Management contract or compensation plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14 (c) of Form 10-K.