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S.C. Supreme Court

THE STATE OF SOUTH CAROLINA
In The Supreme Court

APPEAL FROM THE ADMINISTRATIVE LAW COURT

Ralph K. Anderson III, Administrative Law Judge

Opinion No. 5274 (S.C. Ct. App. filed October 8, 2014)

Duke Energy Corporation.....Petitioner,

v.

South Carolina Department of Revenue.....Respondent.

APPENDIX FOR PETITION FOR A WRIT OF CERTIORARI

VOLUME XIII

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South Carolina Department of Revenue
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Expected return on plan assets	(24)	(23)	(21)
Amortization of prior service cost	1	1	1
ortization of net transition obligation	18	18	18
cognized net actuarial gain	--	--	(1)
curtailments	(3)	--	--
Net periodic post-retirement benefit costs	$ 41	$ 44	$ 44

</TABLE>

<PAGE>

Reconciliation of Funded Status to Accrued Post-Retirement Benefit Costs

<TABLE>
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	December 31,	
	2001	2000
	In millions	
	<C>	<C>
inge in Benefit Obligation		
Accumulated post-retirement benefit obligation at beginning of year	$ 614	$ 562
Service cost	5	5
Interest cost	44	43
Plan participants' contributions	9	7
Actuarial loss	104	39
Benefits paid	(61)	(42)
Plan curtailments	(3)	--
Accumulated post-retirement benefit obligation at end of year	$ 712	$ 614
Change in Plan Assets		
Fair value of plan assets at beginning of year (a)	$ 325	$ 327
Actual return on plan assets	(40)	8
Employer contributions	32	25
Plan participants' contributions	9	7
Benefits paid	(61)	(42)
Fair market value of plan assets at end of year (a)	$ 265	$ 325
Funded status	$(447)	$(289)
Employer contributions	11	9
Unrecognized net experience loss (gain)	111	(56)
recognized prior service cost	4	5
ecognized transition obligation	196	214

Accrued post-retirement benefit costs..... $(125) $(117)

</TABLE>

Principally equity and fixed-income securities. For measurement purposes, plan assets were valued as of September 30.

Assumptions Used for Post-Retirement Benefits Accounting (a)

<TABLE>
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	2001	2000	1999
	Percent		
<S>	<C>	<C>	<C>
Discount rate	7.25	7.50	7.50
Salary increase	4.94	4.53	4.50
Expected long-term rate of return on assets	9.25	9.25	9.25
Assumed tax rate (b)	39.60	39.60	39.60

</TABLE>

(a) Reflects weighted averages across all plans/ /
(b) Applicable to the health care portion of funded post-retirement benefits

For measurement purposes, the net per capita cost of covered health care benefits for employees who have not retired are assumed to have an initial annual rate of increase of 11.5% in 2002 that will gradually decrease to 6% in 2008. For employees that have retired, an initial annual rate of increase of 5% in 2002 will gradually decrease to 6% in 2011. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans.

<PAGE>

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Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	In millions	
<S>	<C>	<C>
Effect on total service and interest costs	$ 2	$ (2)
Effect on post-retirement benefit obligation	47	(40)

</TABLE>

Quarterly Financial Data (Unaudited)

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	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	In millions, except per share data				
<S>	<C>	<C>	<C>	<C>	<C>
2001					
Operating revenues	$16,491	$15,580	$16,718	$10,714	$59,503
Operating income	1,182	880	1,492	546	4,100
EBIT	1,254	902	1,529	571	4,256
Income before cumulative effect of change in accounting principle	554	419	796	225	1,994
Net income	458	419	796	225	1,898
Earnings per share (before cumulative effect of change in accounting principle)					
Basic	$ 0.74	$ 0.54	$ 1.02	$ 0.29	$ 2.58
Diluted	$ 0.73	$ 0.53	$ 1.01	$ 0.28	$ 2.56
Earnings per share					
Basic	$ 0.61	$ 0.54	$ 1.02	$ 0.29	$ 2.45
Diluted	$ 0.60	$ 0.53	$ 1.01	$ 0.28	$ 2.44
2000					
Operating revenues	$ 7,290	$10,926	$15,691	$15,411	$49,318
Operating income	812	794	1,501	706	3,813
EBIT	859	837	1,556	762	4,014
Net income	393	329	770	284	1,776
Earnings per share (a)					
Basic	$ 0.53	$ 0.44	$ 1.04	$ 0.38	$ 2.39
Diluted	$ 0.53	$ 0.44	$ 1.03	$ 0.38	$ 2.38

</TABLE>

(a) Restated to reflect the two-for-one common stock split effective January 26, 2001

During the fourth quarter of 2001, Duke Energy recorded a $43 million provision for non-collateralized accounting exposure to Enron, as well as a $36 million reduction in unbilled revenue receivables, resulting from a refinement in the estimates used to calculate unbilled kilowatt-hour sales.

20. Subsequent Events

On January 31, 2002, Duke Energy announced the planned sale of its DE&S business unit to Framatome ANP, Inc. (a nuclear supplier) for approximately $84 million. Two components of DE&S are not part of the sale. Duke Energy will establish Duke Energy--Energy Delivery Services, formed by the power delivery services component of DE&S, which will continue to supply power delivery solutions to customers. Leadership of the U.S. Department of Energy Mixed Oxide Fuel project will also remain with Duke Energy. The transaction will require a Hart Scott Rodino filing and is expected to close in the second quarter of 2002.

On March 13, 2002, Duke Energy announced the planned sale of DukeSolutions to Ameresco, Inc. Duke Energy expects to close the transaction during the second quarter of 2002, and record a loss of approximately $20 million.

<PAGE>

DUKE ENERGY CORPORATION

SCHEDULE II--VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

<TABLE>
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	Balance at Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions(a)	Balance at End of Period
		In millions			
<S>	<C>	<C>	<C>	<C>	<C>
December 31, 2001:					
Injuries and damages.....	$ 531	$ 31	$ 11	$114	$ 459
Allowance for doubtful accounts.	200	160	4	99	265
Other (b).....	377	201	84	256	406
	$1,108	$ 392	$ 99(c)	$469	$1,130
December 31, 2000:					
Injuries and damages.....	$ 902	$ 18	$ 2	$391	$ 531
Allowance for doubtful accounts.	43	165	8	16	200
Other (b).....	317	40	97	77	377
	$1,262	$ 223	$107(d)	$484	$1,108
December 31, 1999:					
Injuries and damages.....	$ 113	$ 900	$ --	$111	$ 902
Allowance for doubtful accounts.	29	16	6	8	43
Other (b).....	225	134	54	96	317
	$ 367	$1,050	$ 60(d)	$215	$1,262

</TABLE>

(a) Principally cash payments and reserve reversals.
(b) Principally property insurance reserves and litigation and other reserves, included in "Other Current Liabilities" or "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets.
(c) Principally reserves for construction costs, and litigation and other reserves assumed in business acquisitions.
(d) Principally litigation and other reserves assumed in business acquisitions.

<PAGE>

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders of Duke Energy Corporation:

We have audited the accompanying consolidated balance sheets of Duke Energy Corporation and subsidiaries (Duke Energy) as of December 31, 2001 and 2000, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 14. These financial statements and financial statement schedule are the responsibility of Duke Energy's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 Duke Energy as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Deloitte & Touche LLP
Charlotte, North Carolina
February 19, 2002 (March 14, 2002 as to the acquisition of Westcoast Energy, Inc. described in Note 2 and as to the planned sale of DukeSolutions, Inc. described in Notes 3 and 20)

<PAGE>

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Energy Corporation (Duke Energy) are prepared by management, who are responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles in all material respects and necessarily include judgments and estimates of the expected effects of events and transactions that are currently being reported.

Duke Energy's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting

principles. In addition, accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. Duke Energy's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and an internal audit program augment Duke Energy's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed entirely of independent directors who are not employees of Duke Energy. The audit committee meets with management and internal auditors periodically to review accounting control issues and to monitor each group's discharge of its responsibilities. The audit committee also meets periodically with Duke Energy's independent auditors, Deloitte & Touche LLP. The independent auditors have free access to the audit committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

/s/ Keith G. Butler
Keith G. Butler
Senior Vice President and Controller

<PAGE>

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.

Reference is made to "Executive Officers of Duke Energy" included in "Item 1. Business" of this report. See "The Board of Directors," "Information on the Board of Directors" and "Other Information" in the Proxy Statement relating to Duke Energy's 2002 annual meeting of shareholders, incorporated herein by reference.

Item 11. Executive Compensation.

See "Compensation" and "Information on the Board of Directors--Compensation of Directors" in the Proxy Statement relating to Duke Energy's 2002 annual meeting of shareholders, incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

See "Beneficial Ownership" in the Proxy Statement relating to Duke Energy's 2002 annual meeting of shareholders, incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions.

None.

<PAGE>

PART IV.

Item 14. Exhibits, Financial Statement Schedule, and Reports on Form 8-K.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedule included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Years Ended December 31, 2001, 2000 and 1999

Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2000 and 1999

Consolidated Balance Sheets as of December 31, 2001 and 2000

Consolidated Statements of Common Stockholders' Equity and Comprehensive Income for the Years Ended December 31, 2001, 2000 and 1999

Notes to Consolidated Financial Statements

Quarterly Financial Data (unaudited, included in Note 19 to the Consolidated Financial Statements)

Consolidated Financial Statement Schedule II--Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2001, 2000 and 1999

Independent Auditors' Report

All other schedules are omitted because they are not required, or because the required information included in the Financial Statements or Notes.

(b) Reports on Form 8-K

A Current Report on Form 8-K filed on November 20, 2001 contained disclosures under Item 5, Other Events and Item 7, Exhibits.

(c) Exhibits--See Exhibit Index immediately following the signature page.

<PAGE>

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.

<TABLE>
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Date: March 28, 2002

DUKE ENERGY CORPORATION
(Registrant)

By: RICHARD B. PRIORY

Richard B. Priory
Chairman of the Board, President
and Chief Executive Officer

</TABLE>

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.

(i) Principal executive officer:
Richard B. Priory
Chairman of the Board, President and Chief Executive Officer

(ii) Principal financial officer:
Robert P. Brace
Executive Vice President and Chief Financial Officer

(iii) Principal accounting officer:
Keith G. Butler
Senior Vice President and Controller

(iv) All of the Directors:
Richard B. Priory
G. Alex Bernhardt, Sr.
Robert J. Brown
William A. Coley
William T. Esrey
Ann Maynard Gray
Dennis R. Hendrix
Harold S. Hook
George Dean Johnson, Jr.
Max Lennon
Leo E. Linbeck, Jr.
James G. Martin
James T. Rhodes

Date: March 28, 2002

Robert P. Brace, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ ROBERT P. BRACE

Attorney-In-Fact

<PAGE>

EXHIBIT INDEX

Exhibits filed herewith are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting management contracts or compensatory plans or arrangements are designated by a double asterisk (**).

<TABLE>
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Exhibit Number

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2-1 Agreement and Plan of Merger, dated as of November 24, 1996, as amended and restated as of March 10, 1997, among registrant, Duke Transaction Corporation and PanEnergy Corp (filed with Form 8-K dated March 20, 1997, File No. 1-4928, as Exhibit 2(a)).

2-2 Amended and Restated Combination Agreement dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.7).

3-1 Restated Articles of Incorporation of registrant, dated June 18, 1997 (filed with Form S-8, No. 333-29563, effective June 19, 1997, as Exhibit 4(G)).

3-2 Articles of Amendment to Restated Articles of Incorporation of registrant (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 3-A).

3-3 By-Laws of registrant, as amended (filed with Form S-3, File No. 333-52204, Exhibit 4(B)).

3-4 Articles of Amendment to Restated Articles of Incorporation of registrant (filed with Post Effective Amentment No. 2 to Form S-3 of the registrant, file number 333-81573, filed December 12, 2001 as Exhibit 4(B)-1).

4 Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as Rights Agent (filed with Form 8-K dated February 11, 1999).

10-1 Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).

10-2 Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).

10-3 Agreement, dated October 14, 1980, between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-4 Agreement, dated October 14, 1980, between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-5** Directors' Charitable Giving Program (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-P).

10-6** Estate Conservation Plan (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-R).

10-7** Duke Power Company Stock Incentive Plan (filed as Appendix A to Schedule 14A of registrant, March 18, 1996, File No. 1-4928).

10-8 Formation Agreement between PanEnergy Trading and Market Services, Inc. and Mobil Natural Gas,

Inc. dated May 29, 1996 (filed with Form 10-Q of PanEnergy Corp for the quarter ended June 30, 1996, File No. 1-8157, as Exhibit 2).

9** Duke Energy Corporation Long-Term Incentive Plan, as amended (filed as Exhibit A to Schedule 14A of the registrant, March 16, 1998).

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<TABLE>
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Exhibit
Number
- -------
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10-10** Duke Energy Corporation Policy Committee Short-Term Incentive Plan (filed as Appendix B to Schedule 14A of the registrant, March 16, 1998).

10-11 Stock Purchase Agreement between PanEnergy Corp, Texas Eastern Corporation and CMS Energy Corporation, dated as of October 31, 1998 (filed as Exhibit 10 to Form 8-K of the registrant, File No. 1-4928, filed November 5, 1998).

10-12 Merger and Purchase Agreement among Union Pacific Resources Company, Union Pacific Fuels, Inc., Duke Energy Field Services, Inc. and DEFS Merger Sub Corp., dated as of November 20, 1998 (filed as Exhibit 10 to Form 8-K of the registrant, File No. 1-4928, filed December 1, 1998).

10-13** Duke Energy Corporation Executive Savings Plan (filed with Form 10-K Report of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.7).

10-14** Duke Energy Corporation Executive Cash Balance Plan (filed with Form 10-K Report of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.8).

5** Duke Energy Corporation Retirement Benefit Equalization Plan (filed with Form 10-K Report of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.9).

10-16** Form of Key Employee Severance Agreement and Release between the registrant and certain key executives (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-BB).

10-17** Form of Change in Control Agreement between the registrant and certain key executives (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-CC).

10-18 Contribution Agreement by and among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services L.L.C., dated as of December 16, 1999 (filed as Exhibit 2.1 to Form 8-K of the registrant, filed December 30, 1999).

10-19 Governance Agreement by and among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services L.L.C., dated as of December 16, 1999 (filed as Exhibit 2.2 to Form 8-K of the registrant, filed December 30, 1999).

10-20 First Amendment to Contribution and Governance Agreement dated as of March 23, 2000 among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 10.7 (b) to Registration Statement on Form S-1/A (Registration No. 333-32502) of Duke Energy Field Services Corporation, filed on March 27, 2000).

10-21 Parent Company Agreement dated as of March 31, 2000 among Phillips Petroleum Company, Duke Energy Corporation, Duke Energy Field Services, LLC and Duke Energy Field Services Corporation (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-1/A (Registration No. 333-32502) of Duke Energy Field Services Corporation, filed on May 4, 2000).

10-22 Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC by and between Phillips Gas Company and Duke Energy Field Services Corporation, dated as of March 31, 2000 (filed as Exhibit 3.1 to Form 10 of Duke Energy Field Services LLC, File No. 000-31095, filed July 20, 2000).

10-23 First Amendment to the Parent Company Agreement dated as of May 25, 2000 among Phillips

Petroleum Company, Duke Energy Corporation, Duke Energy Field Services, LLC and Duke Energy Field Services Corporation (filed as Exhibit 10.8 (b) to Form 10 of Duke Energy Field Services LLC, File No. 000-31095, filed July 20, 2000).
ABLE>

115

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10.24 $537,500,000 364-Day Credit Agreement dated as of April 19, 2001,among Duke Capital Corporation, the Banks listed therein and Bank One, NA, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.1).

10.25 $537,500,000 Three-Year Credit Agreement dated as of April 19, 2001, among Duke Capital Corporation, the Banks listed therein and Bank One, NA, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.2).

10.26 $550,000,000 364-Day Credit Agreement dated as of August 20, 2001, among Duke Capital Corporation, the Banks listed therein and The Chase Manhattan Bank, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.3).

10.27 $550,000,000 Three-Year Credit Agreement dated as of August 20, 2001, among Duke Capital Corporation, the Banks listed therein and The Chase Manhattan Bank, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.4).

10.28 $475,000,000 364-Day Credit Agreement dated as of August 29, 2001, among Duke Energy Corporation, the Banks listed therein and The Chase Manhattan Bank, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.5).

10.29 $475,000,000 Three-Year Credit Agreement dated as of August 29, 2001, among Duke Energy Corporation, the Banks listed therein and The Chase Manhattan Bank, as Administrative Agent (filed with Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.6).

*12 Computation of Ratio of Earnings to Fixed Charges.

*21 List of Subsidiaries.

*23(a) Independent Auditors' Consent.

*24(a) Power of attorney authorizing Robert P. Brace and others to sign the annual report on behalf of the registrant and certain of its directors and officers.

*24(b) Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.

</TABLE>

he total amount of securities of the registrant or its subsidiaries
horized under any instrument with respect to long-term debt not filed as an
bit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments.

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EXHIBIT 12
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

The earnings to fixed charges ratio is calculated using the Securities and Exchange Commission guidelines.

ABLE>
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	Year Ended December 31,				
<S>	<C> 2001	<C> 2000	<C> 1999	<C> 1998	<C> 1997(a)
	Dollars in millions				
Earnings as defined for fixed charges calculation					
Add:					
Pretax income from continuing operations(b)	$3,303	$3,000	$1,331	$2,055	$1,598
Fixed charges	1,128	1,123	757	599	535
Distributed income of equity investees	156	138	111	94	55
Deduct:					
Preference security dividend requirements of consolidated subsidiaries	170	126	87	44	15
Interest capitalized(c)	139	54	37	15	20
Total earnings	$4,278	$4,081	$2,075	$2,689	$2,153
Fixed charges:					
Interest on debt, including capitalized portions	$ 924	$ 970	$ 644	$ 533	$ 497
Estimate of interest within rental expense	34	27	26	22	23

Preference security dividend requirements of consolidated subsidiaries	170	126	87	44	15
al fixed charges	$1,128	$1,123	$ 757	$ 599	$ 535
Ratio of earnings to fixed charges	3.8	3.6	2.7	4.5	4.0

</TABLE>

(a) Financial information reflects accounting for the 1997 merger with PanEnergy as a pooling of interests. As a result, the financial information gives effect to the merger as if it had occurred January 1, 1997.

(b) Excludes minority interest expenses and income or loss from equity investees

(c) Excludes equity costs related to Allowance for Funds Used During Construction that are included in Other Income and Expenses in the Consolidated Statements of Income

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EXHIBIT 21

List of Subsidiaries

The following is a list of certain subsidiaries of the registrant and their respective states of incorporation (100% owned unless otherwise indicated):

Duke Capital Corporation (Delaware)
Duke Energy North America Trading and Marketing (Delaware)
Duke Energy Trading and Marketing, LLC (Delaware) (approximately 60% owned by Duke Energy)
Texas Eastern Transmission, LP (Delaware)
Westcoast Energy, Inc.

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EXHIBIT 23(A)

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 333-81573, 333-52204, 333-81940 and 333-58820 of Duke Energy Corporation on Form S-3 and Registration Statement Nos. 333-29563, 333-29585, 333-12093, 333-50317, 333-59279 and 333-84222 of Duke Energy Corporation on Form S-8 of our report dated February 19, 2002 (March 14, 2002 as to the acquisition of Westcoast Energy, Inc. described in Note 2 and as to the planned sale of DukeSolutions, Inc. described in Notes 3 and 20), appearing in this Annual Report on Form 10-K of Duke Energy Corporation for the year ended December 31, 2001.

/S/ DELOITTE & TOUCHE LLP
Deloitte & Touche LLP
Charlotte, North Carolina
March 28, 2002

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EXHIBIT 24(A)

DUKE ENERGY CORPORATION

Power of Attorney

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2001
(Annual Report)

The undersigned Duke Energy Corporation, a North Carolina corporation and certain of its officers and/or directors, do each hereby constitute and appoint Robert P. Brace, Robert T. Lucas III and Keith G. Butler, and each of them, to act as attorneys-in-fact for and in the respective names, places, and stead of the undersigned, to execute, seal, sign, and file with the Securities and Exchange Commission the Annual Report of said Duke Energy Corporation on Form 10-K and any and all amendments thereto, hereby granting to said attorneys-in-fact, and each of them, full power and authority to do and perform all and every act and thing whatsoever requisite, necessary, or proper to be

done in and about the premises, as fully to all intents and purposes as the undersigned, or any of them, might or could do if personally present, hereby ratifying and approving the acts of said attorneys-in-fact.

Executed as of the 26th day of February, 2002.

DUKE ENERGY CORPORATION

By /S/ R. B. PRIORY

Chairman, President and
Chief Executive Officer

(Corporate Seal)

ATTEST:

/S/ EDWARD M. MARSH, JR.

Assistant Secretary

<PAGE>

R. B. PRIORY --- R. B. Priory	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/s/ ROBERT P. BRACE --- Robert P. Brace	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KEITH G. BUTLER --- Keith G. Butler	Senior Vice President and Controller (Principal Accounting Officer)
/s/ G. ALEX BERNHARDT --- G. Alex Bernhardt	(Director)
/s/ ROBERT J. BROWN --- Robert J. Brown	(Director)
WILLIAM A. COLEY ---	(Director)

William A. Coley

WILLIAM T. ESREY (Director)

William T. Esrey

/s/ ANN M. GRAY (Director)

Ann M. Gray

/s/ DENNIS R. HENDRIX (Director)

Dennis R. Hendrix

/s/ HAROLD S. HOOK (Director)

Harold S. Hook

<PAGE>

/S/ GEORGE DEAN JOHNSON, JR. (Director)

George Dean Johnson, Jr.

/S/ MAX LENNON (Director)

Max Lennon

/S/ LEO E. LINBECK, JR. (Director)

Leo E. Linbeck, Jr.

/S/ JAMES G. MARTIN (Director)

James G. Martin

/S/ JAMES T. RHODES (Director)

James T. Rhodes

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EXHIBIT 24(B)

DUKE ENERGY CORPORATION

CERTIFIED RESOLUTIONS

Form 10-K Annual Report Resolutions

RESOLVED, That the Audit Committee be and hereby is appointed to review the Form 10-K Annual Report, provide an opportunity for full Board review of such document and approve the document on behalf of the Board of Directors for filing with the Securities and Exchange Commission, with such changes therein as may be deemed necessary or advisable by the officers of the Corporation; and

FURTHER RESOLVED, That the Power of Attorney as presented to the meeting and executed by the Directors present be and hereby is approved in form and content for purposes of filing the Form 10-K Annual Report with the Securities and Exchange Commission.

* * * * * * *

I, SUE C. HARRINGTON, Assistant Secretary of Duke Energy Corporation, hereby certify that the foregoing is a full, true and complete extract from the Minutes of the regular meeting of the Board of Directors of said Corporation held on February 26, 2002, at which meeting a quorum was present.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the Corporate Seal of said Duke Energy Corporation, this the 22nd day of March, 2002.

/s/ Sue C. Harrington

Sue C. Harrington, Assistant Secretary

(Corporate Seal)

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-----END PRIVACY-ENHANCED MESSAGE-----

Duke Power Company
Legal Department
422 South Church Street
Charlotte, NC 28242-0001

DUKE POWER

704/382-8127

(704) 382-8137 Fax

STEVE C. GRIFFITH, JR.
LEWIS F. CAMP, JR.
RAYMOND A. JOLLY, JR.
W. EDWARD POE, JR.
ELLEN T. RUFF
WILLIAM LARRY PORTER
JOHN E. LANSCHE
ALBERT V. CARR, JR.
WILLIAM J. ROWLAN, JR.
ROBERT M. BISANAR
EDWARD M. MARSH, JR.
RONALD V. SHEARIN
W. WALLACE GREGORY, JR.
JEFFERSON D. GRIFFITH, III
JEFFREY M. TREPEL
PAUL R. NEWTON
GARRY S. RICE
LISA A. FINGER
KAROL P. MACK
CHRISTIN J. BRASILETT
OF COUNSEL
WILLIAM I. WARD, JR.
GEORGE W. FERGUSON, JR.

October 25, 1991

OCT 2 3 1991
UTILITIES DIVISION

Mr. Charles W. Ballentine
Executive Director
The Public Service Commission
of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

Re: SCPSC Docket No. 91-216-E

Dear Mr. Ballentine:

Please find enclosed for filing in the above-captioned matter the original and 10 copies of the Proposed Order of Duke Power Company. Attached is a Certificate of Service for the parties of record.

Sincerely yours,

Ellen T. Ruff
Deputy General Counsel

ETR/sch
Enclosures
cc: Parties of Record
Mr. William F. Austin

S.C. PUBLIC SERVICE COMMISSION
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OCT 2 5 1991
RECEIVED

Printed on recycled paper

DE00009259

CERTIFICATE OF SERVICE

I hereby certify that I have this day mailed a copy of the Proposed Order of Duke Power Company (SCPSC Docket No. 91-216-E) to the following:

Ms. Marsha A. Ward, General Counsel
The Public Service Commission
of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

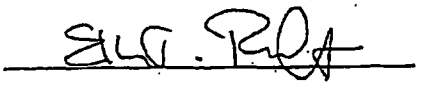
Mr. Steven W. Hamm, Consumer Advocate
Ms. Nancy J. Vaughn, Staff Attorney
Department of Consumer Affairs
P. O. Box 5757
Columbia, South Carolina 29250-5757

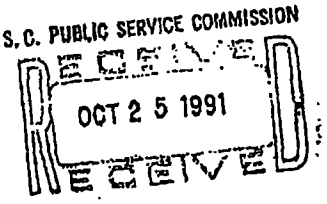
Mr. Arthur G. Fusco
Sherrill and Rogers, PC
P. O. Box 100200
Columbia, South Carolina 29202-3200

Mr. William E. Booth, III
Mays, Foster, Booth & Gunter
2512 Devine Street
Columbia, South Carolina 29205

Mr. Jasper P. Rogers
Route 1, Box 346
Ridgeway, South Carolina 29130

This the 25th day of October, 1991.





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BEFORE THE

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 91-216-E

POSTED
10 23 91

In the Matter of Application by Duke Power Company for Authority to Adjust and Increase Its Electric Rates and Charges	PROPOSED ORDER OF DUKE POWER COMPANY

S.C. PUBLIC SERVICE COMMISSION
OCT 23 1991
UTILITIES DIVISION

Steve C. Griffith, Jr.
Executive Vice President and General Counsel

Ellen T. Ruff
Deputy General Counsel

Karol P. Mack.
Senior Attorney

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Columbia, South Carolina 29211

Attorneys for Duke Power Company

S.C. PUBLIC SERVICE COMMISSION
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OCT 25 1991
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October 25, 1991

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On May 17, 1991, Duke Power Company (Duke or the Company) filed an Application with the Public Service Commission of South Carolina (the Commission) to adjust and increase its retail electric rates and charges, effective for service in accordance with the terms and conditions of §58-27-870, Code of Laws of South Carolina (1976), as amended.1/ The rates proposed by the Company in its Application were designed to increase annual gross revenues from South Carolina retail operations by $72,542,000 or 7.29% based on the test year, i.e., the twelve (12) months ended December 31, 1990.

The proposed revenue increase is distributed among classes of customers by increasing residential revenues by 9.08%, general service revenues by 7.96%, industrial revenues by 5.96%, and outdoor lighting revenues by 6.18%. Different percentage increases for customer classes are proposed because of the existing disparity in rates of return between customer classes.

The principal reason for the requested increase set forth in the Application is the commercial operation of the Bad Creek Hydroelectric Station, a 1,065 MW facility located in the mountains of western South Carolina. Units 1 and 2 began commercial operation on May 15, 1991. Units 3 and 4 began commercial operation on September 3 and September 13, 1991, respectively.

Petitions to intervene were received from the Consumer Advocate, South Carolina Department of Consumer Affairs, the South Carolina Energy Users Committee (SCEUC), the Clifton Power Corporation, and Jasper P. Rogers. These petitions to intervene were allowed by the Commission.

By letter of May 30, 1991, the Executive Director of the Commission required the Company to file with the Commission on or before June 24, 1991, and serve on all parties of record, the testimony and exhibits of the witnesses which the Company intended to offer at the hearing in this matter.

1/ Pursuant to the provisions of that section, the Company gave the Commission the statutory 30-day notice of its intention to file an increase in its rates.

DE00009263

By letter of June 11, 1991, the Executive Director of the Commission scheduled a public hearing on September 23, 1991, and required the Company to provide notice of the public hearing by newspaper notices and bill inserts. The Company furnished proof of publication of the required notice on July 19, 1991.

On June 24, 1991, the Company filed with the Commission its prepared direct testimony and exhibits for the following witnesses: William S. Lee, Chairman of the Board and President, Duke Power Company; Roger G. Ibbotson, President of Ibbotson Associates, Inc.; Richard J. Osborne, Vice President, Finance, Duke Power Company; Donald H. Denton, Jr., Senior Vice President, Planning and Operating, Duke Power Company; W. R. Stimart, Vice President, Rates and Regulatory Affairs, Duke Power Company; Ronald E. White, Senior Vice President, Foster Associates, Inc.; and Thomas S. LaGuardia, President, TLG Engineering, Inc. On September 3, 1991, Duke filed Supplemental Testimony and Supplemental Exhibit 1 of W. R. Stimart. Duke filed Supplemental Exhibit 2 on September 20, 1991. During the hearing, Duke filed Supplemental Exhibit 3.

By letter of August 8, 1991, the Executive Director of the Commission required the Commission Staff and all other parties of record to file their testimony on or before September 9, 1991. The following testimony was filed: for the Consumer Advocate: Paul Chernick, Resource Insight, Inc.; Peter J. Lanzalotta, Whitfield Russell Associates; Phillip E. Miller, Riverbend Consulting, Inc.; John B. Legler, Professor of Banking and Finance in the College of Business Administration, University of Georgia; for the Commission Staff: I. Curtis Price, III, A. R. Watts, and James E. Spearman; for the South Carolina Energy Users Committee: Nicholas Phillips, Jr.2/ The Commission also

2/ Pursuant to their respective requests, the Consumer Advocate and SCEUC were granted an extension of time to September 13 to file their testimony.

received a written statement from Jasper P. Rogers on or about September 21, 1991.

On September 16, 1991, Duke filed updated and revised testimony of Roger G. Ibbotson, and the Consumer Advocate filed a revised exhibit of Peter J. Lanzalotta.

On September 11, 1991, in Order No. 91-775, the Commission scheduled a prehearing conference for September 18, 1991, at 10:00 a.m. The prehearing conference was held as scheduled.

The public hearing before the Commission commenced as scheduled on September 23, 1991. William F. Austin, Esquire, Steve C. Griffith, Jr., Esquire, Ellen T. Ruff, Esquire, and Karol P. Mack, Esquire, represented the Company; Marsha A. Ward, Esquire, represented the Commission Staff; Steven W. Hamm, Esquire, Raymon E. Lark, Jr., Esquire, Nancy J. Vaughn, Esquire, and Richard Elam, Esquire, represented the Consumer Advocate; Arthur G. Fusco, Esquire, represented SCEUC; William E. Booth, III, Esquire, represented Clifton Power Corporation; and Jasper P. Rogers appeared on his own behalf. The public hearing was completed on September 26, 1991.

On September 25, 1991, the Company filed the rebuttal testimony of Donald H. Denton, Jr. and William F. Reinke. Subsequent to the hearing, the Consumer Advocate filed the surrebuttal testimony of Philip E. Miller and Paul Chernick on October 2, 1991.

A night hearing was held in Greenville, South Carolina on October 7, 1991. The Commission heard testimony from the following witnesses: Tom Blank, Jim Schumer, Earl Mills, Joe Jelks, Jim McKittrick, Ron Vankirk, John E. Newman, Robert Keenan, and Kris Risley.

Clifton Power Corporation was granted an extension of time to September 17 to file its testimony, but did not file any testimony.

DE00009265

Based upon the verified Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission now makes the following findings of fact:

FINDINGS OF FACT

General Procedural Issues

1. Duke is engaged in the generation, transmission, distribution, and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas.

2. Duke is an electric utility operating in the State of South Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. The Company's retail operations in South Carolina are subject to the jurisdiction of this Commission pursuant to S.C. Code Ann. §§58-27-10 et seq. (1976), as amended. The Company's wholesale operations in South Carolina are subject to the jurisdiction of the Federal Energy Regulatory Commission (hereinafter "FERC").

Test Period

3. The test period for purposes of this proceeding is the 12-month period ended December 31, 1990, adjusted for certain known and measurable changes.

Requested Increase

4. Duke, by its Application, sought an increase in its basic rates and charges to its South Carolina retail customers of $72,542,000. Subsequent to the filing of the Application, the Company lowered its request to $68,384,000.

Cost Allocation

5. The summer coincident peak (summer CP) demand allocation methodology is the most appropriate method for making jurisdictional allocation of production costs and for making fully distributed cost allocations among customer classes in this proceeding. Consequently, each Finding of Fact

appearing in this Order which deals with the overall level of rate base, revenues, and expenses for South Carolina retail service has been determined based upon the summer CP allocation method.

Test Period Revenue

6. The appropriate operating revenues for Duke for the test year under present rates and after accounting and pro forma adjustments are $994,450,000 for service to the South Carolina retail jurisdiction.

Bad Creek Hydroelectric Station

7. The Commission finds that the costs of the Bad Creek Hydroelectric Station were prudently incurred. In so doing, the Commission specifically finds that all four units were in commercial operation prior to the commencement of the hearing; that the station was completed under Duke's budget; that considering Duke Power's system generation needs, the choice of pumped storage was prudent compared to other types of generation such as combustion turbines; that Bad Creek is needed to enable Duke to meet the load on its system and to maintain a minimum level of reserve requirements; and that the Bad Creek Station is used and useful. The costs of the Bad Creek Station should be included in Duke's rate base.

Carolina Power & Light Co. Contract (Schedule J)

8. No adjustment to the test period for billings to Carolina Power & Light Company under Schedule J is appropriate.

Test Year and Post-Test Year Cost Increases

9. It is appropriate to increase operation and maintenance expenses by $4,832,000 to reflect increases in wage rates and related fringe benefit costs that occurred during the test year. This adjustment also results in a corresponding increase in payroll taxes of $419,000.

10. It is appropriate to increase operation and maintenance expenses by $4,287,000 to reflect increases in wage rates and related fringe benefits and payroll taxes which occurred after the end of the test year.

Implementation of SFAS 106

11. It is appropriate to increase operation and maintenance expenses by $3,830,000 to reflect the implementation of accrual accounting for other post-retirement benefits expense in accordance with Statement of Financial Accounting Standards No. 106.

Demand-Side Management Programs

12. The Commission Staff, the Consumer Advocate, and the Company entered a Stipulation relating to Demand-Side Management (DSM) cost deferral. The Stipulation is reasonable and is approved by the Commission.

13. It is appropriate to increase operation and maintenance expenses by $3,911,000 to reflect known increases in costs associated with the Company's load control and interruptible service demand-side management programs.

Depreciation and Decommissioning Expenses

14. The appropriate depreciation rates for purposes of setting depreciation expense are as follows:

Function	Rate
Production	
Steam	2.57%
Nuclear	
Decommissioning	1.61%
Investment	3.09%
Total Nuclear	4.70%
Hydraulic	1.98%
Other	0.74%
Transmission	2.57%
Distribution	3.59%
General (Summary Only)	3.59%

15. In determining decommissioning expense to be included in cost of service, it is appropriate to assume zero real return for qualified nuclear decommissioning trust investments and 1% for nonqualified investments.

16. The appropriate components of decommissioning expense to be included in cost of service are as follows:

(Dollars in Thousands)		Annual Cost	
Unit	Total Cost	System	S. C. Retail
Oconee 1	$164,792	$10,491	$ 2,722
Oconee 2	158,311	10,101	2,621
Oconee 3	202,855	12,218	3,171
Oconee ISFSI	21,750	1,325	344
McGuire 1	171,246	8,950	2,323
McGuire 2	186,265	9,294	2,412
Catawba 1	23,476	1,199	311
Catawba 2	26,163	1,271	330
TOTAL	$954,858	$54,849	$14,234

Other Operating Expenses

17. The reasonable level of test year operating revenue deductions for the Company after pro forma adjustments is $837,757,000.

Capital Structure and Rate of Return

18. The appropriate capital structure for the Company for use in this proceeding is as follows:

Item	Percent
Long-Term Debt	40.50%
Preferred Stock	9.68%
Common Equity	49.82%
Total	100.00%

19. The proper embedded cost rates for long-term debt and preferred stock are 8.78% and 7.74%, respectively.

20. The reasonable rate of return on common equity that Duke should be allowed an opportunity to earn is 13.17%, which the Commission adopts for this proceeding. Combined with the debt and preferred cost rates and the capital

structure set forth in the table below, which the Commission finds reasonable, the overall rate of return is 10.87%.

Item	Percent	Cost	Weighted Rate
Long-Term Debt	40.50%	8.78%	3.56%
Preferred Stock	9.68%	7.74%	.75%
Common Equity	49.82%	13.17%	6.56%
TOTAL	100.00%		10.87%

Material and Supplies

21. The reasonable allowance for materials and supplies investment is $73,668,000.

Plant Held for Future Use

22. The reasonable allowance for plant held for future use is $4,402,000.

Working Capital

23. The reasonable allowance for working capital is $57,832,000.

Rate Base

24. Duke's reasonable original cost rate base used and useful in providing service to the public within the State of South Carolina is $1,834,972,000, consisting of electric plant in service of $2,868,210,000; net nuclear fuel of $88,747,000; plant held for future use of $4,402,000; materials and supplies of $73,668,000; and allowance for working capital of $57,832,000, reduced by accumulated depreciation and amortization of $924,185,000, accumulated deferred income taxes of $315,569,000, operating reserves of $14,180,000, and customer deposits of $3,953,000.

Revenue Requirement

25. Based upon the foregoing, Duke should increase its annual level of gross revenues under present rates by $68,384,000. The annual revenue requirement approved herein is $1,062,834,000 which will allow Duke a reasonable

opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

Rate Design

26. The rate designs, rate schedules, miscellaneous charges, and terms and conditions proposed by the Company are appropriate and should be adopted, except as specifically modified herein.

27. The rate of return for the Industrial class is outside of the "band of reasonableness", a band or range of plus or minus 10% of the average retail rate of return. Consequently, the revenue increase approved herein should be distributed in order to move the Industrial class rate of return to the band of reasonableness.

28. The modifications to the penalty provisions of Interruptible Rider IS proposed by the Company should be adopted. The credit should not be increased in view of the substantial participation by customers at the current level of credit.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings concerning the Company's business and legal status is contained in the Company's verified Application and in prior Commission Orders in this Docket of which the Commission takes notice. These Findings of Fact are essentially informational, procedural, and jurisdictional in nature; and the matters which they involve are essentially uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings concerning the test period and the amount of the revenue increase requested by the Company is contained in the verified Application of the Company and the testimony and exhibits of Duke witnesses Lee and Stimart.

On May 17, 1991, the Company filed an Application requesting approval of rate schedules designed to produce an increase in gross revenues of $72,542,000.

Public Service Commission of South Carolina

Accountability Report

Fiscal Year 2010-2011

PETITIONER'S EXHIBIT

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Section I – Executive Summary

- **Mission and values:**

  The Public Service Commission of South Carolina regulates the rates and services of investor owned public utilities in the state of South Carolina and establishes just and reasonable standards for their rates and services.

  The mission of the Public Service Commission is to serve the public by providing fair, open, and effective regulation of the state's public utilities through the faithful administration of the law and the regulatory process.

- **Major achievements for 2010-2011**

  A main focus for the Commission during the 2010-2011 fiscal year was identifying emerging issues within the regulated industries and engaging in discussions with members of the regulated community on these issues. With new developments on the federal level concerning transmission and renewable energy sources, and proposed new EPA regulations and FCC rulings on the horizon, the Commission desires to be proactive in response to issues that affect the entities they regulate. Over the course of the year, the Commission held over twenty-seven allowable ex parte meetings and workshops to stay abreast of emerging issues. Topics included "Emerging and Foundational Issues in the Electric Utility Sector," "Settlement Policy and Procedure," "South Carolina Natural Gas Research and Development Essentials," and "Issues Related to Renewable Energy Sources" (Table 7.2-1, pages 23 and 24). These hearings were open to the public, and notices were posted on the Commission's website.

  The Commission also desired to provide consumers with more information concerning the regulatory process to aid in fulfillment of its mission in providing a forum for fair, open, and effective regulation. In collaboration with practitioners, the Commission developed an online form for use by the public to file a letter of protest against a utility. The form standardizes the process, and ensures that the necessary information is included with the protest. Also, in collaboration with its customers and stakeholders, the Commission made enhancements to its website to improve the display of information and functionality. In addition, the Commission's website was updated to add educational information for consumers on the regulatory process, energy efficiency and demand side management, and net metering.

  The Commission continued to attain leadership positions on the national level furthering the professional development of the Commission. PSC commissioners held chairmanships of three National Association of Regulatory Utility Commissioners (NARUC) committees and one subcommittee this year, and four commissioners served on the NARUC Board of Directors. Commissioner David Wright was elected as the First Vice President of NARUC. He will assume the presidency of the organization in the fall of 2011. Several commissioners were appointed to key strategic federal panels and committees. These positions ensure that South Carolina and the Southeast's positions are represented on national issues such as transmission in the Eastern Interconnection, smart grid, gas pipeline safety, and broadband expansion (Table 1.7-1, pages 11 and 12).

  During the 2010-2011 fiscal year, the Commission presided over and ruled on several significant cases in the telecommunications and electric industries. These cases involved

rulings on the federal and state universal service funds and expenses related to the expansion of nuclear energy production at Duke Energy Carolinas, LLC and South Carolina Electric & Gas Company facilities.

The following paragraphs are summaries of the Commission's most significant cases for FY 2010-2011:

- In accordance with the Base Load Review Act, South Carolina Electric & Gas Company (SCE&G) sought approval for updates and revisions to schedules related to the construction of Units 2 and 3 at the V.C. Summer Nuclear Station near Jenkinsville, SC. The revisions included the removal of approximately $438 million in owner's contingency funds that were included in the cost schedules previously approved by the Commission, but reversed on appeal by the South Carolina Supreme Court, and the addition of $174 million for construction of the units. As a result of these updates and revisions, the capital cost of the units in 2007 dollars was reduced to approximately $4.3 billion, and gross capital costs were reduced to approximately $5.8 billion.

- Duke Energy Carolinas, LLC (Duke) filed for approval to incur additional pre-construction costs of $229 million through December 31, 2013, for the Lee Nuclear Station in Cherokee County, SC. In an amended application, Duke sought approval of nuclear generation preconstruction expenditure of no more than $75 million during the period January 1, 2011 through June 30, 2012. All parties, with the exception of one, agreed that this was the minimum amount estimated to be necessary to keep the nuclear option available and signed a settlement agreement. The Commission concurred and approved the settlement agreement.

- AT&T filed complaints against several competing telecommunications companies. These complaint cases centered on the interpretation and application of Sections 251 and 252 of the Telecommunications Act of 1996. At issue is how promotional programs and discounts are to be treated. The resolution of these complaints will establish criteria for interpreting a significant portion of the remedies contained in Sections 251 and 252 and the FCC regulations regarding those sections. A ruling is pending in these cases.

- Allied Wireless Communications Corporation d/b/a Alltel filed its application for designation as an Eligible Telecommunications Carrier (ETC) to serve both rural and nonrural areas in South Carolina. The FCC is currently revising the federal Universal Service Fund (USF) and plans to have these revisions completed by the end of 2011. Any revisions to the existing federal USF could have a great impact on how much federal USF funding will be available to South Carolina, how many ETCs are to be designated, the criteria upon which ETC designation will be determined, and what services the federal USF will support. The Commission ruled to hold in abeyance a ruling on Alltel's application until at least the end of 2011 to allow time for the FCC to finalize its revision of the federal USF.

- The South Carolina Cable Television Association (SCCTA) filed a petition seeking to transition the Interim Local Exchange Carrier (ILEC) Fund into the South Carolina Universal Service Fund (SCUSF). At oral arguments, the SCCTA argued that the ILEC Fund must transition into the SCUSF when funding for the SCUSF is

finalized and adequate to support the obligations of the ILEC Fund. Other parties argued that the SCUSF must be consistent with the federal USF which is currently being revised by the FCC. The Commission denied the petition of the SCCTA finding that the SCUSF, at this time, was neither finalized nor sufficient to support the obligations of the ILEC Fund, and, thus, the ILEC Fund should not be transitioned into the SCUSF.

- **Key strategic goals for present and future years:**

  The Commission must be alert to and anticipate emerging issues in the industries it regulates, including federal regulatory developments. Maintaining effective communications with its customers and participation in national organizations integrated into the utility sectors will aid in achieving this goal.

  The Commission will continue to improve its hearing procedures so as to provide the public with accessible, transparent, and effective regulation of public utilities and provide the public with clear information about the regulatory process and its decisions.

  An on-going goal of the Commission is to improve its operations through technological advances. As opportunities are identified, the Commission will investigate the costs and benefits and take the appropriate actions.

- **Key strategic challenges:**

  The nation's electric and gas industries are subject to a broad range of regulatory models across the country, and regulators have taken a number of measures to increase competition and investment. And with growing pressure for the generation of energy using alternative energy sources, the Commission must effectively regulate these industries, safeguarding the ratepayers, without unduly burdening the industries or stifling competition.

  The public relies on the Commission's online systems to access information related to its operations. The Commission must budget funds to support maintenance and development of the systems.

  The water and sewer industries are also faced with stricter environmental regulations, as well as the rising cost of water itself, which is often purchased from third party providers and distributed to the customer by the utilities, and can lead to increased operating expenses.

  Another key strategic challenge that faces the Commission is the need to maintain an effective regulatory environment without unnecessarily impeding change in a dynamic marketplace.

- **How the accountability report is used to improve performance:**

  The Accountability Report is used in conjunction with the agency's strategic plan, which is developed under the guidance of the State Regulation of Public Utility Review Committee (PURC), to measure organizational performance and gauge overall progress in fulfilling the organization's mission and objectives.

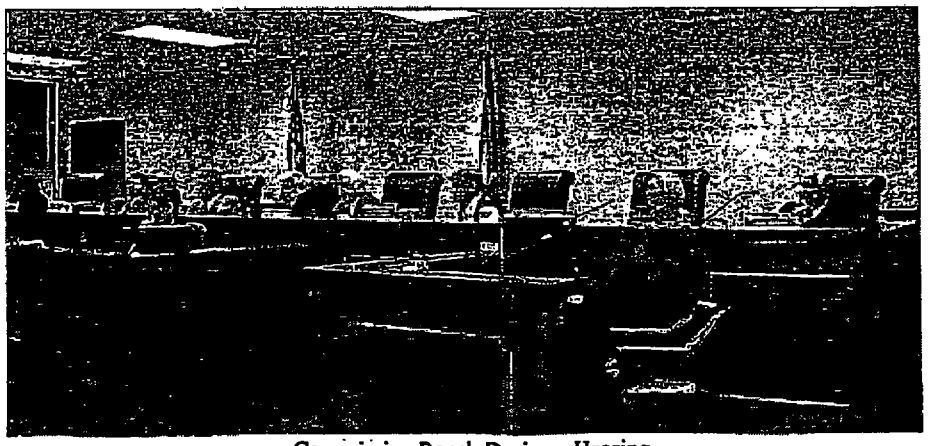
Section II – Organizational Profile

- **Main products and services and primary methods by which these are delivered:**

The PSC serves as a quasi judicial body charged with the adjudication of cases involving the state's investor owned utilities that provide electric, gas, telecommunications, water, sewer, and various transportation services to the citizens of South Carolina. As such, it is the Commission's duty to accept all filings, pleadings, testimony, etc. that are associated with cases presented before the Commission and to rule on such cases in the form of issuance of orders. These orders put into full force and effect rulings on:

- Rates and schedules
- Certificates of operation for telecommunications companies and transportation carriers
- Consumer complaints
- Service issues
- Territorial assignments of regulated utilities
- Telecommunications interconnection agreements
- Prudency reviews of electric and gas utilities' fuel purchasing practices
- Arbitration of disputes involving certain federal statutes, such as the Federal Telecommunications Act of 1996
- Reviews of allowable costs for Chem-Nuclear Systems, LLC
- Standards under the federal Energy Policy Act of 2005
- Siting and financing for generating facilities

The Commission's Docket Management System (DMS), an on-line case management system (http://dms.psc.sc.gov), maintains the documents and events associated with a case. Hearings on cases are held before the commissioners (below), and decisions are issued from the bench at the weekly public Commission Agenda Meetings. Orders are subsequently issued to the parties of record in the cases (Chart 7.1-1, page 21).



Commission Bench During a Hearing

- **Key customers and their key requirements/expectations:**

  As a regulatory agency, the key customers of the Public Service Commission are the utilities subject to the jurisdiction of the Commission and the public who are served by these regulated utilities. The statutory mandate of the Public Service Commission is to ensure that the rates charged by the utilities are just and reasonable. The Commission also ensures that service quality standards are maintained and that utility customers are treated fairly.

- **Key stakeholders:**

  The regulations and rulings of the Commission directly impact other state agencies such as the Office of Regulatory Staff (ORS). In addition, NARUC, the Southeastern Association of Regulatory Utility Commissioners (SEARUC), the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Eastern Interconnection Planning Council (EIPC), and the Universal Service Administrative Company (USAC) benefit from the Commission's involvement with these organizations. The State Regulation of Public Utility Review Committee is the joint legislative committee charged with the oversight of the Commission as a result of Act 175.

- **Key suppliers and partners:**

  The Commission employs the services of software designers to develop, enhance, and maintain its online systems, and a network support specialist to maintain its network software in conjunction with the Commission's information technology staff.

- **Operation location:**

  The Public Service Commission's office is located on the first floor of the Saluda Building in the Synergy Business Park in Lexington County. The street address is 101 Executive Center Drive, Suite 100, Columbia, SC 29210.

- **Employment statistics:**

  In FY 2010-2011, the Public Service Commission had thirty-eight classified full time equivalent positions, one temporary employee, one grant position, and one contract position.

- **Regulatory environment under which organization operates:**

  The Commission regulates investor-owned electric, natural gas, telecommunications, water, and wastewater utilities for which numerous federal, state and local regulations exist. The Commission also regulates the transportation of passengers, household goods, and hazardous waste, which must conform to various safety and market regulations in order to obtain certificates of public convenience and necessity allowing them to operate in South Carolina. Finally, the Commission determines the allowable costs for Chem-Nuclear Systems, LLC, a regional low-level radioactive waste disposal facility located in Barnwell, South Carolina.

Most Commission orders may be appealed to the state Supreme Court. In addition, the Commission has some overlapping jurisdiction with federal entities such as the FCC, FERC, and NERC.

- **Performance improvement systems:**

The Commission currently records and monitors on a monthly basis several key inputs and outputs in its docket processing system. These key identifiers such as new dockets, hearings, directives, orders and electronic filings assist management in allocating resources to meet demands (Charts 7.1-1 thru 7.1-4, and 7.2-2 thru 7.2-4, pages 21-26).

Activity related to agency Hearing Officers and Hearing Examiners is also tracked to ensure that this component of the Commission is utilized whenever possible to improve the timeliness of proceedings. For the past several years, there has been a steady increase in the number of rulings made through these Commission Staff appointments – one indicator of the increasing efficiency with which the Commission resolves complaints and applications (Chart 7.1-5, page 23).

The State Regulation of Public Utilities Review Committee serves as the joint legislative committee that oversees the operations of the Commission as a result of Act 175. The committee is chaired by Senator Thomas Alexander, with Representative William Sandifer serving as vice chairman. Other legislative members are Senators Bradley Hutto and Luke Rankin, and Representatives Michael Forrester and Harry Ott. In addition, there are four members from the public sector, namely, Elizabeth Atwater, Erik Ebersole, John Simmons, and Helen Zeigler that also serve on the committee. Each year the Commission develops objectives and action plans and reports on the results to the committee. These objectives are in line with the Commission's strategic plan and goals and are the framework against which the agency's performance is evaluated.

An external system is also employed which features customer satisfaction surveys to identify areas of concern and improvement with respect to operations, timeliness, and quality of service. This year, members of the practicing legal community that participate in hearings at the Commission and members of the public sector were surveyed on a variety of topics, including satisfaction with the Commission's online systems, prefile testimony guidelines, and the role of hearing examiners and officers at the Commission. Results of the surveys are studied to determine areas of improvement.

At least twice a year, the Commission has meetings with its Advisory Committee, which consists of more than thirty members from the legal community who regularly practice before the Commission (Figure 3.6-2, page 15). Discussions center on operations and regulations, suggestions for improvement, and feedback on the Commission's priorities and objectives.

Organizational structure:

The Public Service Commission is comprised of a seven member board elected by the General Assembly for four year terms, representing each congressional district plus an at-large member.

Public Service Commission of South Carolina

Commissioner
John E. "Butch" Howard
Charleston, SC

Representing District 1
Term Expires June 30, 2012

Commissioner
David A. Wright
Columbia, SC

Representing District 2
Term Expires June 30, 2014

Commissioner
Randy Mitchell
Saluda, SC

Representing District 3
Term Expires June 30, 2012

Commissioner
Elizabeth B. "Lib" Fleming
Spartanburg, SC

Representing District 4
Term Expires June 30, 2014

Commissioner
G. O'Neal Hamilton
Bennettsville, SC

Representing District 5
Term Expires June 30, 2012

Commissioner
Nikiya "Nikki" Hall
Columbia, SC

Representing District 6
Term Expires June 30, 2014

Commissioner
Swain E. Whitfield
Blythewood, SC

At-Large Representative
Term Expires June 30, 2012

Chief Clerk/Administrator
Jocelyn G. Boyd
Columbia, SC

The Chief Clerk and Administrator manages the day-to-day operations of the Commission. Four departments, Administrative, Clerk's Office, Legal, and Advisory Staff, perform the daily duties of the Commission. All departments have a manager reporting directly to the Chief Clerk.

- **Expenditures/Appropriations Chart:**

Actual expenditures for fiscal years 2009-2010 and 2010-2011, and appropriations for 2011-2012 are shown in the following chart. The utilities regulated by the Public Service Commission are assessed to provide funding for the Commission. The Commission was the recipient of a grant from the American Recovery and Reinvestment Act of 2009 (ARRA). The grant will be used to fund activities at the Commission, ORS, and PURC.

Major Budget Categories	FY 09-10 Actual Expenditures		FY 10-11 Actual Expenditures		FY 11-12 Appropriations Act	
	Total Funds	General Funds	Total Funds	General Funds	Total Funds	General Funds
Personal Service	$ 2,693,903		$ 2,685,526		$ 3,045,395	
Other Operating	$ 698,686		$ 913,120		$ 902,545	
Special Items						
Permanent Improvements						
Case Services						
Distributions to Subdivisions						
Fringe Benefits	$ 683,722		$ 747,666		$ 846,368	
Non-recurring						
Total	**$ 4,076,311**		**$ 4,346,312**		**$ 4,792,308**	

- **Major Program Areas Chart:**

Program Number and Title	Major Program Area Purpose (Brief)	FY 09-10 Budget Expenditures	FY 10-11 Budget Expenditures	Key Cross References for Financial Results
Administrative Department	Provides administrative support and direction to ensure consistency, compliance, financial integrity and fulfillment of the agency's mission.	State: Federal: Other: $ 2,326,523 Total: $ 2,326,523 % of Total Budget: 57%	State: Federal: Other: $2,116,143 Total: $2,116,143 % of Total Budget: 49%	Chart 7.2-3 Chart 7.2-4 Chart 7.5-1
Clerk's Office	Processes all legal documents that are filed with the Commission. Creates and mails all notices of filings. Processes public inquiries. Prepares and maintains all hearing documents.	State: Federal: Other: $694,479 Total: $694,479 % of Total Budget: 17%	State: Federal: Other: $675,089 Total: $675,089 % of Total Budget: 15%	Chart 7.1-1 Chart 7.1-4 Chart 7.2-2 Chart 7.2-3 Chart 7.5-1 Table 7.6-1
Legal Department	Advises the Commission regarding pending cases. Drafts legal documents.	State: Federal: $ 5,445 Other: $581,517 Total: $586,962 % of Total Budget: 14%	State: Federal: $339,646 Other: $660,712 Total: $1,000,358 % of Total Budget: 23%	Chart 7.1-1 Chart 7.1-2 Chart 7.1-3 Chart 7.1-5 Table 7.4-1 Table 7.6-1
Office of Advisory Staff	Provides technical advice to the commissioners and staff.	State: Federal: $ 6,882 Other: $461,465 Total: $468,347 % of Total Budget: 12%	State: Federal: Other: $554,724 Total: $554,724 % of Total Budget: 13%	Chart 7.1-1 Table 7.4-1 Chart 7.4-2

Below: List any programs not included above and show the remainder of expenditures by source of funds.

Remainder of Expenditures:	State: Federal: Other: Total: % of Total Budget:	State: Federal: Other: Total: % of Total Budget:

Section III – Elements of Malcolm Baldrige Award Criteria

Category 1 – Senior Leadership, Governance, and Social Responsibility

The Public Service Commission performs an annual exercise of developing performance measures in the areas that are critical to the successful operation of the agency. Under direction of PURC, key performance goals and action items are identified. These goals and action items translate into the Commission's performance measurement system which guides the agency in the management of its processes.

Senior leaders (i.e. the Commission and its professional staff) set, deploy, and ensure two-way communication for short and long term direction and organizational priorities through the performance measurement process described above. Senior leaders regularly review the progress on the action items established in the performance measurement process. PURC reviews the performance measures on a yearly basis as well.

The goals developed in the performance measurement process reflect the values by which the Commission operates: fairness in its decision-making, aspiring to professional excellence, and providing value and accountability to the citizens of South Carolina.

The Commission encourages individual contribution to performance and operations improvements and rewards such contributions through its newly restructured Employee Recognition Program (Shout Out!). Developmental and agency training needs are identified by senior management, and as deficiencies are identified, solutions are developed to provide the necessary instruction.

Senior leadership fosters ethical behavior by attending an annual ethics seminar, publishing a periodic newsletter that addresses ethics issues, and the designation of in-house personnel to resolve issues that arise in the day to day operations. The Commission adheres to the SC Code of Judicial Conduct, the State Ethics Laws, and Title 58 of the South Carolina Code of Laws in its operations. This year's annual ethics training featured a distinguished panel including Senator Bradley Hutto, Cathy Hazelwood, General Counsel of the State Ethics Commission, Dean Robert Wilcox from the University of South Carolina School of Law, and The Honorable Thomas Cooper, Jr., a retired circuit court judge.

Senior leaders promote a focus on customers and other stakeholders by utilizing the Commission's Advisory Committee in a series of forums that address operations and procedures at the Commission, independent surveys of parties that practice before the Commission, and soliciting customer feedback through online surveys. The Commission also desires to provide consumers with more information concerning the regulatory process to aid in fulfillment of its mission in providing a forum for fair, open, and effective regulation.

The Commission addresses the current and potential impact on the public with respect to its services, facilities, and operations by conducting hearings that are open to the public. In these hearings, public comment is both requested and desired. In addition, the companies that are under jurisdiction of the Commission must publish notices in local media concerning changes to their operations as mandated by the Commission's regulations.

Public hearings and workshops are also held to inform the public of emerging utility issues in the industries regulated by the Commission. Some of the topics from this year's workshops include "Hazardous Waste Transportation in the United States," "Issues Related to Renewable Energy

Sources," "An Update on Construction of New Nuclear Units at V.C. Summer Nuclear Station," and "Improvements Within Regulated Water Companies in South Carolina."

Senior leaders maintain fiscal, legal, and regulatory accountability through regular communication with PURC. The Commission's budget must be reviewed by PURC prior to submission for approval from the General Assembly.

Senior leaders regularly review the progress on the action items that were established in the performance measures development process. In addition, key statistics related to operations are reported and tracked on a monthly basis.

The performance measurement process defines the organizational values for the Commission, and the developed action items provide a means to meet the goals established for the Commission. Senior leadership improves its own effectiveness by identifying areas where additional knowledge and skills are required in order to meet the objectives in the performance measurement system.

The commissioners of the Public Service Commission are elected by the General Assembly. The chairman and the senior staff work to promote and educate future organizational leaders by identifying programs that will cultivate the skills necessary to lead the agency. PSC commissioners held chairmanships of three NARUC committees and one subcommittee this year, and as a result of their leadership positions, organized and led many of the NARUC national meetings. Commissioner David Wright was elected as the First Vice President of NARUC. He will assume the presidency of the organization in the fall of 2011. Four PSC commissioners served on the NARUC Board of Directors during this past year. Several commissioners were appointed to key strategic federal panels and committees. Below is a listing of the positions held by the Commission:

Commissioner Leadership Positions 2010-2011

Commissioner Howard District 1	Chairman	NARUC Committee on Water
	Board Member	NARUC Board of Directors
	Director	NARUC Utility Rate School
	Member	Water Research Foundation's Public Council on Drinking Water Research
	Member	Department of Homeland Security/EPA Water Sector Government Coordinating Council
Commissioner Wright District 2	First Vice President	NARUC Executive Committee and Board of Directors
	Chairman	NARUC Subcommittee on Nuclear Issues and Waste Disposal
	Member	NARUC Washington Action Committee
	Member	NARUC Committee on Electricity
	Chairman	Nuclear Waste Strategy Coalition
	Board Member	Advisory Board of the Institute of Public Utilities at Michigan State University
	Board Member	Electric Power Research Institute (EPRI)
	Member	Keystone Energy Board

Commissioner Mitchell District 3	Member	NARUC Committee on Telecommunications
	Member	FCC & NARUC Advanced Services Conference
	Vice Chairman	NARUC Special Access Study Committee
	Vice Chairman	NARUC Committee on Critical Infrastructure
	Board Member	Universal Service Administrative Company (USAC)
Commissioner Fleming District 4	Chair	NARUC Committee on Critical Infrastructure
	Board Member	NARUC Board of Directors
	Member	NARUC Committee on Electricity
	Secretary	Eastern Interconnection States Planning Council Executive Committee
	Member	Eastern Interconnection Planning Council Stakeholders Steering Council
	Member	White House Smart Grid Working Group
	Member	Advisory Council for the Center for Public Utilities at New Mexico State University
Commissioner Hamilton District 5	Chairman	NARUC Committee on Gas
	Board Member	NARUC Board of Directors
	Member	NARUC Subcommittee on Nuclear Issues and Waste Disposal
	Member	National Petroleum Council
	Member	Advisory Board Gas Technology Institute
Commissioner Hall District 6	Member	NARUC Committee on Energy Resources and the Environment
	Member	NARUC Utility Marketplace Access Subcommittee
Commissioner Whitfield At-Large	Member	NARUC Committee on Critical Infrastructure
	Member	NARUC Committee on Gas
	Member	NARUC Pipeline Safety Task Force

Table 1.7-1 Commissioner Leadership

Senior leaders use the performance measurement process to create an environment for performance improvement and accomplishment of strategic objectives.

Senior leadership recognizes the importance of staying up to date in all areas of the regulatory process in this fast changing and volatile environment. Members of the Commission and staff regularly attend training sessions (conferences, workshops, webinars, etc.) on emerging issues within the industries regulated by the Commission (Table 7.2-1, page 24 and Table 7.4-1, page 27). They encourage the workforce to seek additional knowledge and training when required.

Senior leadership interacts with the entire workforce through the work processes. High performance is recognized and rewarded using an employee recognition program, which was restructured during this past year to allow more opportunities for recognition at all organizational levels. Formal recognition by senior management is made on a quarterly basis, with informal recognition taking place on an as needed basis.

The Commission's senior leadership actively supports and strengthens the communities in which the agency operates by volunteering their time and donating their resources to numerous civic organizations. Some of the recipients are the Harvest Hope Food Bank, the United Way, Rotary Clubs, Ruritan Clubs, the Irmo-Chapin Recreation Commission, the American Red Cross, the American Cancer Society, and the Colorectal Cancer Action Committee.

Category 2 - Strategic Planning

The regulatory climate today is dynamic and can be best addressed through a proactive regulatory process that reflects the increased competitive nature of the companies within the nation and the state, while seeking to best serve the needs of all of the citizens of the state.

PURC serves as the joint legislative committee that oversees the operations of the Commission as a result of Act 175. Senior management, with input from the Commission's Advisory Committee, develops the strategic plan and implementation process, which is presented to PURC for final approval.

Our strategic planning process addresses our organization's strengths, weaknesses, opportunities, and threats by identifying those areas that are critical to the successful operation of the agency and the systems that must be in place and function at optimum performance to achieve our goals. Those critical operations are functions performed by the clerk's office related to filings of matters and service of orders, hearings conducted by the commissioners, and the legal and advisory staff's advice to the Commission and assistance in drafting orders. Senior management is involved in the day to day operations of these functions and is able to make necessary adjustments to meet goals. PURC oversees the operations at the Commission and recommends objectives that need to be met in order to comply with regulations.

The public utility arena has become increasingly competitive over the last decade with the introduction of deregulation on both the federal and state levels. With new developments on the federal level concerning transmission and renewable energy sources, and proposed new EPA regulations and FCC rulings on horizon, the Commission desires to be proactive in response to issues that affect the entities they regulate. This is done through the Commission's affiliation with NARUC and SEARUC and their partnered organizations, and attendance at educational functions (conferences, seminars, webinars, etc.). To keep informed of potential legislation or court rulings on the federal or state level that would impact the Commission, an alert system is in place to notify senior leadership and includes an internal electronic discussion board (blog).

The Commission is continually striving to maintain cutting edge technology with respect to its operations. As new technology becomes available, the information technology staff investigates its potential benefits and makes recommendations to senior management.

With the guidance of PURC and input from the Commission's Advisory Committee, action plans are identified and developed by senior management so that the critical operations of the Commission will have the necessary resources to function at optimum performance. These resources may be human, systematic or technological. Senior management oversees the day to day critical operations of the Commission and is able to allocate resources to meet the demands.

Strategic objectives, action plans, and related performance measures are communicated and deployed throughout the agency through senior management at weekly, monthly, and quarterly meetings.

Progress is measured on action plan items by means of periodic update sessions with senior management. New tasks and additional resources are assigned, if necessary, at these meetings to ensure that the action item continues on track.

Evaluation and improvement of the strategic planning process requires senior management's knowledge of the short and long term goals for the agency coupled with the results from the performance measurement program and input from customers and key stakeholders.

Key strategic objectives and action plans are outlined in the following chart:

Strategic Planning

Program Number and Title	Supported Agency Strategic Planning Goal/Objective	Related FY 10-11 and beyond Key Agency Action Plan/Initiative(s) and Timeline for Accomplishing the Plan	Key Cross References for Performance Measures
Administrative Department	The Administrative Department provides administrative support and direction to ensure consistency, compliance, financial integrity, and fulfillment of the agency's mission.	Maintain all personnel-related records; record and file annual reports from regulated companies; provide a variety of information technology support services; handle internal mail distribution, photocopying, and central supplies; publish newsletters and reports; conduct training sessions for staff; develop agency budget; perform financial functions related to the agency such as payroll and general ledger accounting. [2011-2012]	Chart 7.2-3 Chart 7.2-4 Chart 7.5-1
Clerk's Office	The Clerk's Office processes all legal documents that are filed with the Commission. Creates and mails all notices of filings and directives. Schedules hearings before the Commission. Prepares and maintains all hearing documents.	Process all legal documents filed with the agency; prepare notices; maintain accurate and complete files of the Commission's dockets; provide copies of recent and historical Commission orders through the agency's online docket management system (DMS); provide court reporter services and transcripts, provide copies of matters filed in dockets to the public on the DMS; maintain company tariffs; maintain the Order Index System. [2011-2012]	Chart 7.1-1 Chart 7.1-4 Chart 7.2-2 Chart 7.2-3 Chart 7.5-1 Table 7.6-1
Legal Department	The Legal Department provides legal advice to the commissioners and staff, and drafts the oral decisions of the Commission.	Properly set out in writing the decisions of the Commission; provide appropriate consultation to the Commission staff on all laws and regulations pertaining to the utility and transportation industries; attend national and regional conferences related to laws and regulations; review and revise regulations. [2011-2012]	Chart 7.1-1 Chart 7.1-2 Chart 7.1-3 Chart 7.1-5 Table 7.4-1 Table 7.6-1
Office of Advisory Staff	The Office of Advisory Staff provides technical advice to commissioners and staff.	Provide policy input to the commissioners regarding changing and evolving regulations in reference to jurisdictional utilities; develop and present educational seminars to commissioners and staff; attend national and regional conferences related to laws and regulations; interact with external groups such as NARUC, FERC, NRRI, EIPC, etc. via electronic communication and conference calls. Assist in preparation and review of commission's rulings. [2011-2012]	Chart 7.1-1 Table7.4-1 Chart 7.4-2

Category 3 - Customer Focus

Through strategic planning, our customer and stakeholder groups have been identified as individuals and businesses acquiring the services provided by our regulated utilities, citizens of our state who would be affected by the unsafe operation of utility services, and utilities authorized to operate within the state of South Carolina.

A variety of procedures are employed to determine customer needs, expectations, and satisfaction. These include:

- Workshops/Training Classes
- Generic Proceedings
- Advisory Focus Groups
- Publications/Public Service Announcements/Websites
- Performance Surveys (formal and informal)
- Formal Proceedings

Figure 3.6-1 Attendees at "The Rate Case Experience" Ex Parte Briefing

Through the Commission's formal hearings and meetings and its online public information systems, customers are able to access the information concerning proceedings before the Commission.

Figure 3.6-2 Webmaster Bret Stenhouse discussing new procedure.

The Commission meets with its Advisory Committee to address issues related to its operations and procedures. As in previous meetings; working groups are assembled to assist the Commission in developing solutions to new regulations, procedures, and operations. Members of the Advisory Committee contribute helpful suggestions, and their input is valued and taken into account when changes to operations or procedures are required (Figure 3.6-2).

The Commission developed surveys for use in evaluating and improving its website (www.psc.sc.gov) and online systems (DMS and ETariff). Electronic surveys were sent to members of the public who have made contact with the Commission, and a more detailed electronic survey was sent to members of the Commission's Advisory Committee. Eighty-four percent of the respondents stated that the information on the Commission's website was current and up to date. Results of the survey will be used to identify areas for improvement.

By responding to our customers in a timely fashion and meeting their expectations with respect to service received, whether it is from one of our online systems or direct communication with a staff member, the Commission continually strives to improve its operations. Because the Commission must operate under the Code of Judicial Conduct, the agency is limited in its direct contact with its

customers, but will continue to make improvements to its operations and procedures to provide an environment that leads to healthy customer relations.

Category 4 - Measurement, Analysis, and Knowledge Management

Key performance measures are identified as those functions that are critical to the successful operation of the agency to achieve its goals. Those critical operations are functions performed in the filings of matters and service of orders, hearings conducted by the Commission, and preparation and issuance of orders. Weekly meetings with senior management are held to discuss upcoming filings, hearings, and issues and allocate resources to meet them.

Monthly totals (number of new dockets, filings, hearings, directives, orders, etc.) are collected, analyzed, and reported to senior management. Senior management is involved in the day to day operations of these functions and can adjust workloads to ensure deadlines are being satisfied.

Where available, measures are compared to past trends to assist management in planning future workloads.

Whenever possible, data is collected and reported automatically to ensure its integrity, reliability, and accuracy. In cases where manual collection is required, data is validated to ensure accuracy.

Although job functionality is specific to industry and workload is structured by industry, general cross training of duties does occur to handle the instances of vacations, sick leave, training, etc. Additionally, standardization of operations is performed when applicable. Internal "Best Practices" documents have been developed to assist in this standardization.

Category 5 – Workforce Focus

Workloads are organized and managed according to function. From the time a docket is created, every department at the Commission is actively involved in its filing and disposition. A high level of cooperation exists between departments because of the interdependence in processing a docket. Because of this interdependence, senior management meets weekly to ensure that all departments are working on the same set of short term goals and sharing critical information.

The Commission fills agency vacancies utilizing existing personnel if possible. For recruitment from outside the agency, the Commission partners with the SC Office of Human Resources' E-Recruitment System. A member of senior management is involved in the hiring, orientation, and training of new hires.

In order to adapt to the changing regulatory market, the Commission requires a knowledgeable staff to assist the Commission in adjudicating cases. Developmental and agency training needs are identified by senior management. As deficiencies are identified, solutions are developed to provide the necessary instruction. Individual training requests can be made to develop expertise or knowledge in an area of an employee's job description. Informal evaluations are recorded for training that is performed off-site. Internal "Best Practices" documents have been developed to standardize functions where possible.

The Commission received a grant from the American Recovery and Reinvestment Act of 2009 (ARRA) to ensure that staff has the appropriate technical expertise to process regulatory activities pertaining to ARRA electricity related initiatives such as energy efficiency, demand response management, renewable energy, smart grid, and transmission. The Commission sponsored two seminars in which commissioners and staff members attended. The seminars featured presenters from the Institute of Public Utilities at Michigan State University and the National Regulatory Research Institute (NRRI). Sessions were held on the basics of utility regulation and electricity's current challenges (Figure 5.6-1). The NRRI seminar was open to the public, and nearly one hundred people from the regulatory and legal community, as well as representatives from the electric utility industry, were present. A follow-up seminar on transmission is planned for later in the year.

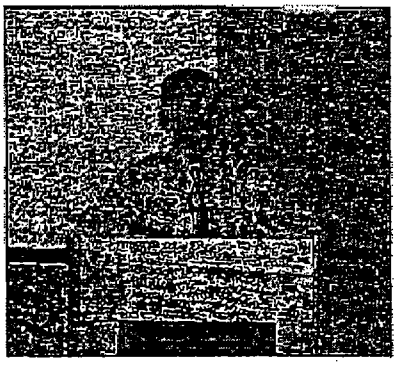


Figure 5.6-1 – NRRI Director Scott Hempling

Senior management is involved in leadership on the national level with numerous affiliated organizations and stays informed of current issues within the industries regulated by the Commission (Table 7.4-3, page 29). Involvement in these organizations ensures that South Carolina and the Southeast's positions are represented on national issues such as transmission in the Eastern Interconnection, smart grid, gas pipeline safety, and broadband expansion. These leadership positions assist in fulfilling one of the main goals of the Commission for the year, namely, "To strive for excellence such that it will be recognized for its achievements."

The mission of the Commission is to provide fair, open, and effective regulation of the state's public utilities. In order to be effective, the Commission must be engaged and informed. This is accomplished through involvement in national organizations (NARUC, FERC, Nuclear Waste Strategy Coalition, etc.) and attendance at conferences, seminars, and webinars (Table 7.4-1, page 27).

Members of the Commission receive training in ethical practices through seminars and newsletters. This year a diverse panel consisting of a state legislator, the State Ethics Commission General Counsel, the USC School of Law dean, and a retired circuit judge conducted seminars for commissioners and staff. (Figures 5.6-2 and 5.6-3)

Figure 5.6-2 – Senator Brad Hutto conducts ethics training for the PSC.

Figure 5.6-3 –Dean Robert Wilcox, from the USC School of Law, engages PSC staff during training.

Additional technology and appropriate tools required to perform job functions are utilized when resources are available. The Commission encourages individual contribution to performance and operations improvements and rewards such contribution utilizing its restructured Employee Recognition Program (Shout Out!). The Commission recognizes members of its workforce for years of service.

The Synergy Business Park is a safe and secure workplace. Coded entrances provide security to employees. The Commission has a prevention and wellness program in place to educate its workforce on good health practices for the home and workplace. Activities include cholesterol and blood pressure screening, speaker's bureau, stress management, weekly health tips, and flu shots (Figures 5.14-1 and 5.14-2).

Figure 5.14-1 – Staff Attorney Josh Minges (r)

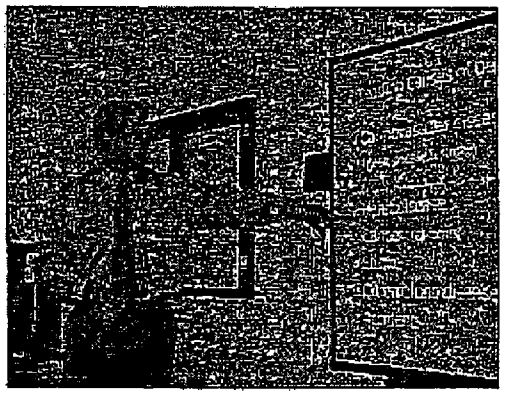


Figure 5.14-2 – John Leech of Lexington Medical Center Cardiovascular Rehab Center

Category 6 - Process Management

Most of the processes utilized by the Commission are dictated by statute or regulation. Whenever a party desires a hearing before the Commission, the party must file a formal application requesting a hearing. The Clerk's Office reviews the application to ensure that it complies with all legal requirements. Once the Clerk's Office accepts the application, it is noticed on the Commission's agenda as an advised item to begin the notification process.

In most cases, public notice must be given, often in bill inserts and notices published in newspapers of the affected areas. Deadlines are set for intervention and the filing of testimony, and a hearing date is scheduled. Discovery, information requests, and interrogatories follow the procedures set forth in the Code of Laws of South Carolina. A hearing is held, and a court reporter transcribes the proceeding (Figure 6.2-1).

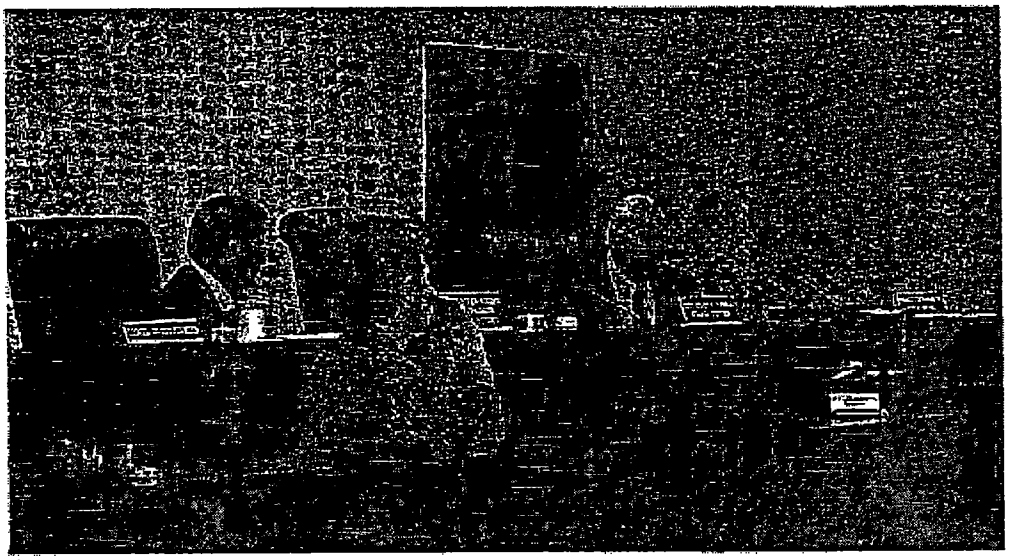


Figure 6.2-1 – Commission Hamilton (r) questions the witness during hearing.

Parties generally file legal briefs or proposed orders shortly after the hearing transcripts are released. The commissioners render their decision at a Commission Meeting, and the Legal Department drafts an order, which is then made available for the commissioners' review. Any input from commissioners is incorporated before the order is finalized, and the Clerk's Office mails a copy of the order to the parties of record. Any party to the hearing can ask the commissioners to reconsider their decision and can appeal the decision to the Appellate Court. This process most often applies to our jurisdictional utilities.

The DMS is used extensively in the process management of these tasks. Since it is an online system, the parties of record and the general public can monitor the activity of a case. Daily reports are generated from the DMS that list activity on the system with respect to process management (new dockets, filing of matters, issuance of orders, etc.). In addition, the Commission's main website contains the latest information on current issues and cases.

Weekly meetings with senior management are held to discuss upcoming filings, hearings, and issues and allocate resources to meet them. Because senior management is involved in the day to day operations, adjustments can be made to the processes when demand requires.

Meeting statutory deadlines for hearings, orders, etc. allows the Commission to appraise the effectiveness of its operations and institute changes to operations to improve the regulatory process. The Commission recently implemented changes to its order drafting process to allow the use of issuance of orders in the form of directives issued from the bench in many routine procedural matters. This operational change improves productivity and yields timelier results for the parties. In addition, the Commission meets at least twice a year with its Advisory Committee to evaluate the Commission's operations. With input from staff, senior leadership, the Commission's Advisory Committee, and customer feedback, improvements and updates to processes are identified in order to improve performance.

Key support processes include information management, financial and accounting, personnel, and office management functions. Through the performance measures plan approved by PURC, objectives and action items are reviewed on a regular basis to determine if adjustments need to be made to processes and workforce to meet the objectives of the plan.

Senior management regularly reviews the agency's budgetary status and makes adjustments where necessary based on developed contingency plans. Prior to the beginning of the fiscal year, departmental managers submit budgets for education, equipment, training and other budgetary needs for their areas. Throughout the year, managers update their requirements and budget revisions are made.

Category 7 - Business Results

Key business results for the 2010-2011 year include improvements in customer communications and customer education, and professional development of commissioners and staff.

7.1 The Commission's primary duty is to adjudicate cases involving the state's investor owned utilities.

- The Commission held 94 hearings this past fiscal year and issued over 850 orders (Chart 7.1-1). Fiscal year 2010-2011 did not see the activity generated from the multiple electric and water rate cases that were adjudicated in 2009-2010, in which 15 additional public hearings were held across the state.

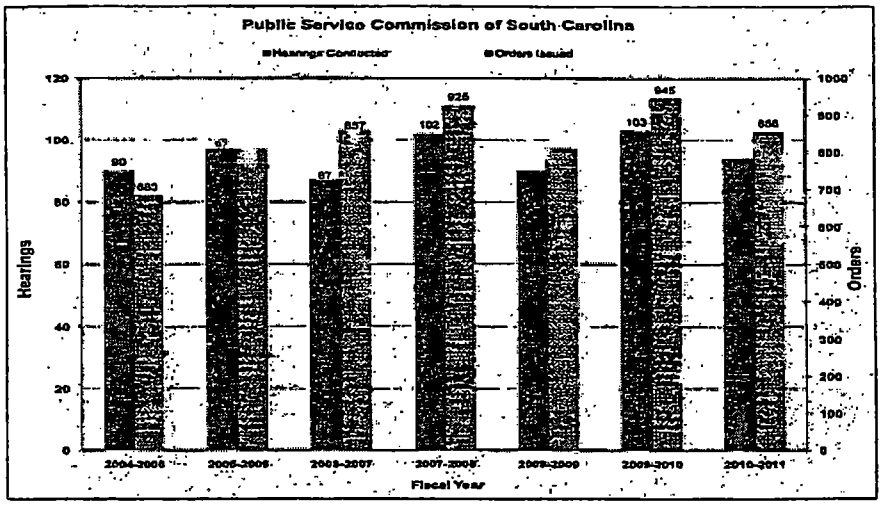


Chart 7.1-1 PSC Hearings and Orders

- The Commission's hearings encompass the telecommunications, electric, gas, water/wastewater, and transportation industries (Chart 7.1-2).

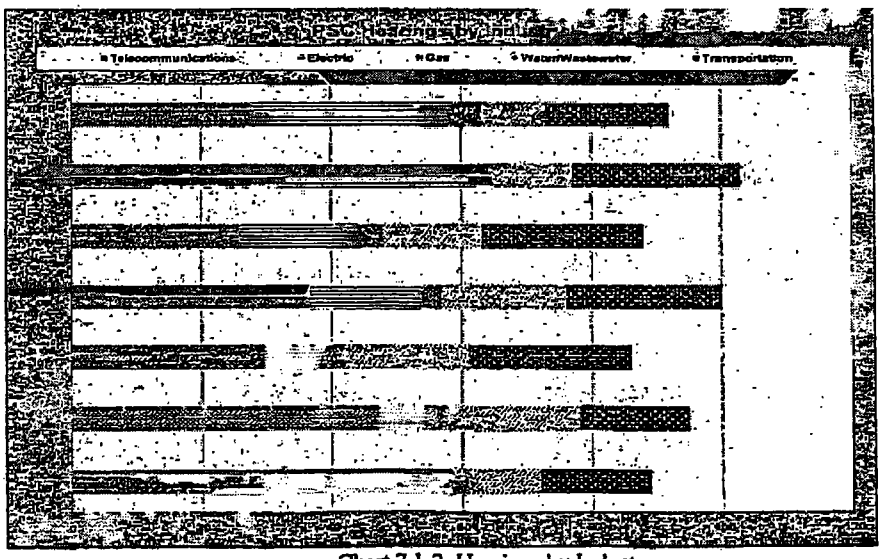


Chart 7.1-2 Hearings by Industry

- The number of cases in the electric industry heard by the Commission has been steadily increasing over the past few years as shown in Charts 7.1-2 and Chart 7.1-3. This is due to the impact of new issues that must be addressed from a regulatory standpoint. Some of these issues are energy efficiency and demand side management, renewable energy, plug-in electric vehicles, the expansion of nuclear generating facilities, FERC and state authority issues, and new EPA regulations. This trend is expected to continue.

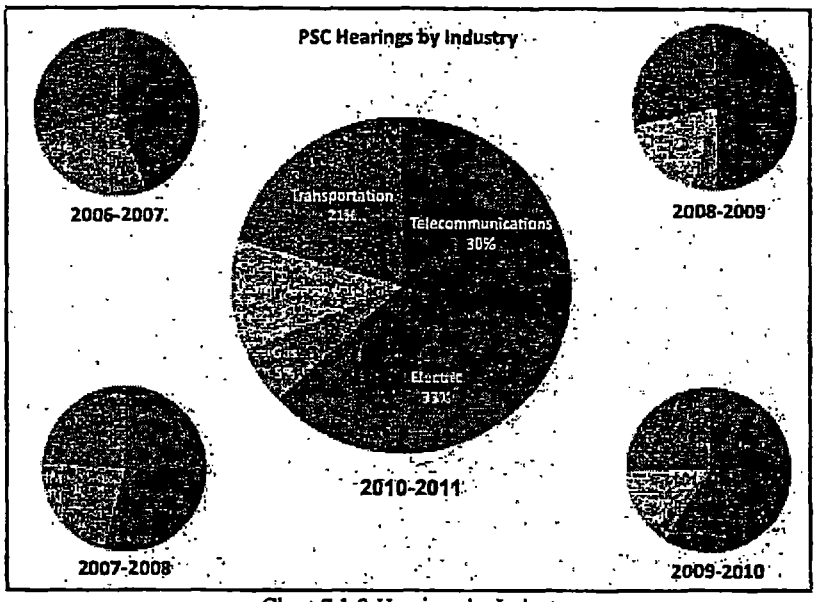


Chart 7.1-3 Hearings by Industry

- The Commission opened 454 new dockets during the fiscal year. A new docket is opened whenever an application is submitted to the Commission, a complaint, petition, or agreement is filed, or a rulemaking or fuel case proceeding comes before the Commission (Chart 7.1-4). This figure is on par with recent years' new dockets.

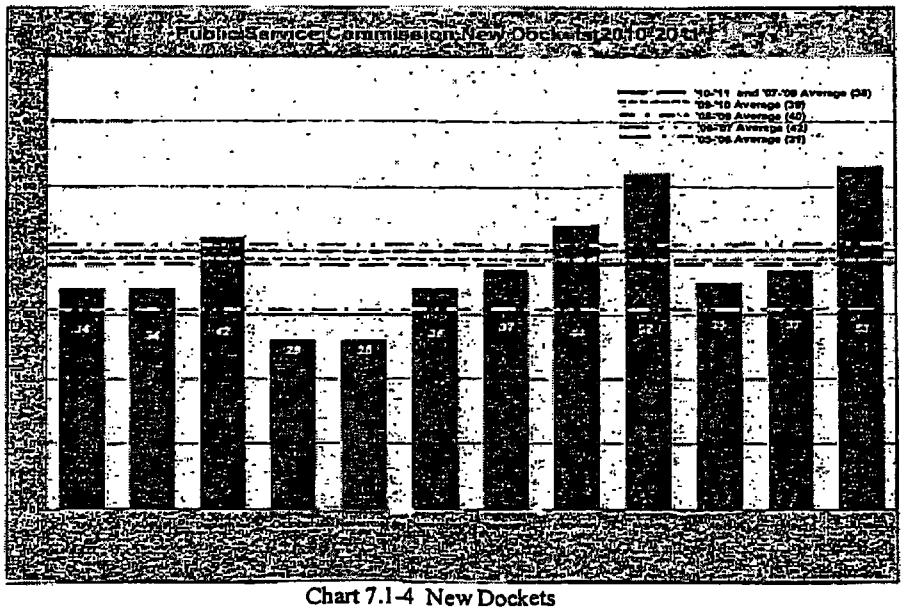


Chart 7.1-4 New Dockets

- Hearing examiners and officers are appointed to dispose of procedural matters and report findings of fact in appropriate cases. Each year has shown a steady increase in the number of rulings made through these Commission staff appointments – one indicator of the increasing efficiency with which the Commission resolves complaints and applications (Chart 7.1-5).

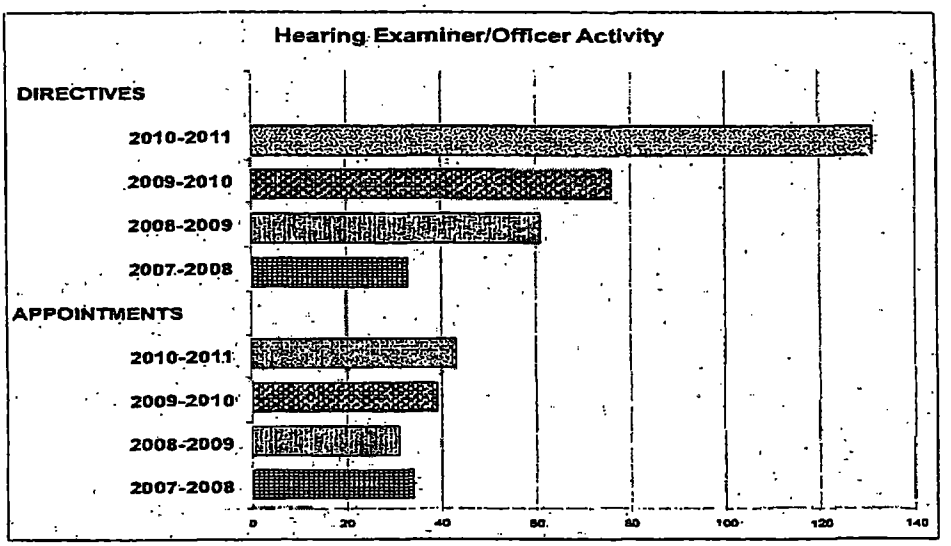


Chart 7.1-5 Hearing Examiner/Officer Activity

7.2 This year, the Commission heavily engaged in activities to increase customer awareness and education. In addition, the Commission also concentrated on effective dialogue with customers and stakeholders on emerging issues in the industries regulated by the Commission.

- The Commission conducted a series of public workshops to foster a better understanding of regulatory developments in the industries it regulates (Table 7.2-1). Topics included "Emerging and Foundational Issues in the Electric Utility Sector," "Settlement Policy and Procedure," "South Carolina Natural Gas Research and Development Essentials," and "Issues Related to Renewable Energy Sources." These workshops allowed the Commission to continue to provide a transparent regulatory process while maintaining effective communications with its customers and stakeholders.

Date	Topic
July 16, 2010	Fundamentals of Electricity Regulation in South Carolina
August 18, 2010	Emerging and Foundational Issues in the Electric Utility Sector
August 25, 2010	Financial Conditions and Future Generation and Infrastructure Projects – Progress Energy Carolinas, Inc.
September 8, 2010	Hazardous Waste Transportation in the United States – US Nuclear Infrastructure Council

Date	Topic
September 9, 2010	Commissioner NARUC Activities and Involvement
September 29, 2010	Settlement Policy and Procedure
October 8, 2010	Educational, Foundational, and Emerging Issues in the Gas Utility Sector
October 21, 2010	Update on Construction Progress of New Nuclear Units at V.C. Summer Nuclear Station – South Carolina Electric & Gas Company
October 25, 2010	The Rate Case from the Financial Officer's Perspective
November 8, 2010	Tour of Chem-Nuclear Systems, LLC
November 9, 2010	Integrated Resource Plan – Duke Energy Carolinas, LLC Integrated Resource Plan – Progress Energy Carolinas, Inc.
December 2, 2010	The Telecommunications Network
December 15, 2010	Issues Related to Renewable Energy Sources – Progress Energy Carolinas, Inc.
December 15, 2010	South Carolina Natural Gas Research and Development Essentials
January 20, 2011	Merger of Progress Energy, Inc. and Duke Energy Corporation
January 27, 2011	Duke Energy Carolinas' Economic Development Activities and 2010 Successes
February 22, 2011	Update on Transition with Emphasis on Broadband Future Plans for 2011 – Frontier Communications of the Carolinas, Inc.
March 25, 2011	Duke Energy Carolinas, LLC's Look Ahead at 2011 and Review of Nuclear Operations
April 6, 2011	South Carolina Emergency Preparedness – SC Office of Regulatory Staff and SC Energy Office
April 18, 2011	Actions Taken to Maintain and Improve Service – Alpine Utilities, Inc.
April 19, 2011	Pilot Weather Normalization Adjustment Mechanism – South Carolina Electric & Gas Company
April 20, 2011	Energy Issues from an Industrial Customer Perspective – Nucor Steel – South Carolina Gas Pipeline Safety – Office of Regulatory Staff
April 28, 2011	2011 Integrated Resource Plan and Update on Demand Side Management Program – South Carolina Electric & Gas Company
May 24, 2011	Proposed Plug-in Electric Vehicle Charging Station Pilot Program – Duke Energy Carolinas, LLC
June 1, 2011	South Carolina Electric & Gas Company's 2011 Integrated Resource Plan – South Carolina Coastal Conservation League, the Southern Alliance for Clean Energy, and Upstate Forever
June 7, 2011	Actions Taken to Maintain and Improve Service – Harbor Island Utilities, Inc.
June 21, 2011	Update Concerning Proposed EPA Regulations – Progress Energy Carolinas, Inc.

Table 7.2-1 2010-2011 Public Workshops

- In collaboration with practitioners, the Commission developed an online form for use by the public to file a letter of protest against a utility. The form standardizes the process and ensures that the necessary information is included with the protest. This form is being highly utilized.

- Enhancements to the agency's website www.psc.sc.gov and its online docket management system (http://dms.psc.sc.gov) allowed the public more access to information related to the Commission's operations. The Commission's homepage is used to inform the public of upcoming hearings and announcements, proposed regulations, and consumer information.

- The Commission made enhancements to its website to improve the display of information and functionality. In addition, the Commission's website was updated to add educational information for consumers on the regulatory process, energy efficiency and demand side management, and net metering.

- The Commission's online tariff system (ETariff) (http://etariff.psc.sc.gov) allows users to view and search tariffs online, and allows organizations to file promotions and revisions to tariffs electronically using the web based system. Currently, there are over 630 tariffs in the database, with most telecommunications companies and all electric and gas company tariffs available online. The percentage of returning visitors to the site is increasing as the system becomes established.

- Posting of matters related to docketed cases on DMS is a vital function of the Clerk's Office (Chart 7.2-2). Once the information is in DMS, it is available for public access over the internet. This information consists of applications, testimony, exhibits, notices, correspondence, orders, etc.

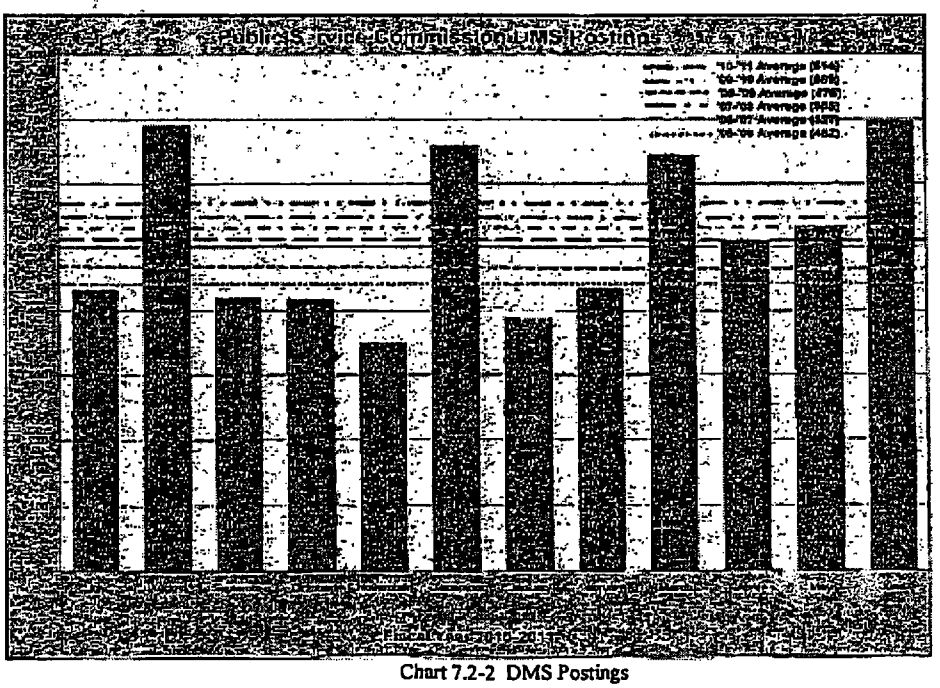


Chart 7.2-2 DMS Postings

- The DMS's database was expanded to include orders dating back to 1952. Although the number of pageviews has dropped off somewhat from the previous year, the chart below (Chart 7.2-3) shows the activity level on the DMS website year after year and reinforces the usefulness of the system and the public's dependence on the information contained in the system.

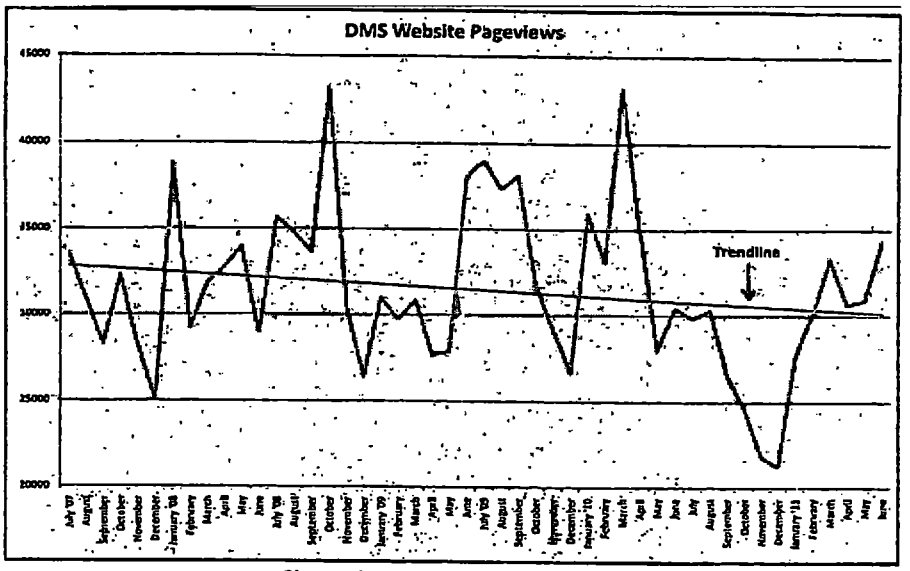


Chart 7.2-3 DMS Website Activity

- As shown in Chart 7.2-4, the Commission's website is very accessible using internet search engines. As new information is added to the site, such as details on the significant cases and consumer information, search engines are able to direct people to the site.

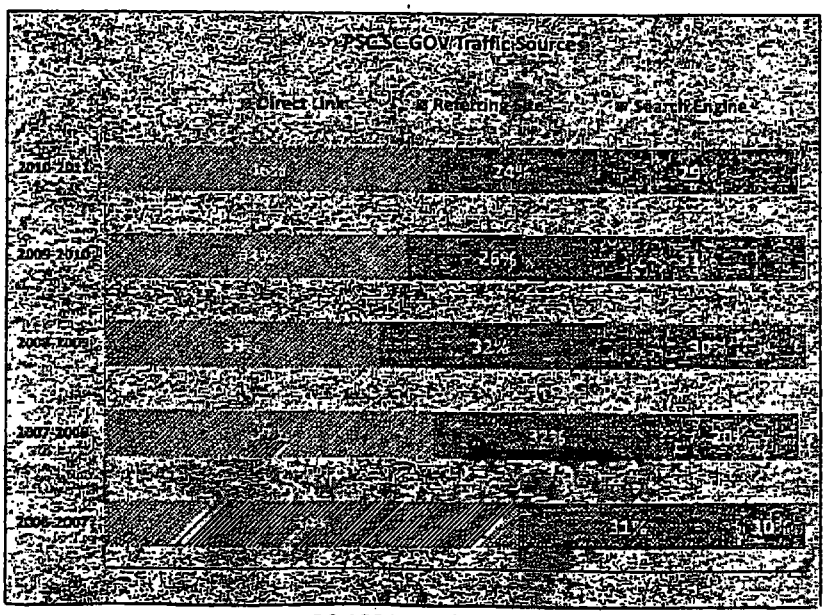


Chart 7.2-4 PSC Website Traffic

7.3 The Commission completed the 2010-2011 fiscal year within its operating budget, despite uncollected revenues of $80, 005. The FY 11-12 budget was submitted in a timely manner.

7.4 The Commission aspires to professional excellence and, in a readily changing environment, must be alert to and anticipate emerging issues in the industries it regulates.

- Public workshops and allowable ex parte briefings were held to develop a better understanding of regulatory developments and issues that affect the industries regulated by the Commission (Table 7.2-1).

- Members of the Commission attended numerous forums, workshops and meetings to stay informed of emerging issues within the regulated industries. As technological advances are made in the industries regulated by the Commission (e.g. renewable energy, shale gas drilling, and smart grid), the Commission must learn how the integration of these technologies will impact industries (Table 7.4-1).

Emerging Issues Educational Sessions

National Electricity Forum
Eastern Interconnection States Planning Council Meetings
Eastern Interconnection Planning Council Sector Steering Committee Meetings
Institute of Public Utilities at Michigan State University Grid School
Transmission Business School
Transmission Technologies Workshop
South Carolina Biomass Council Meetings
Blue Ribbon Commission Meeting
Governor's Conference on Energy
White House Smart Grid Subcommittee Meeting
Electric Infrastructure Security Summit
South Carolina Energy Users Committee Meeting
Bonbright Center Electric and Natural Gas Conference
National Petroleum Council Public Interest Advisory Council Meetings
Gas Technology Institute Public Interest Committee Meeting
American Gas Association Centerpoint Technology Lab Tour
National Association of Water Companies (NAWC) Annual Conference
NAWC Water Policy Forum
Water Research Foundation Advisory Council Meetings
Society of Utility and Regulatory Financial Analysts Forum
Government Coordinating Council's Critical Infrastructure Partnership Advisory Council Water Sector Committee Meetings
South Carolina Telephone Association Conferences
Utility Wall Street Dialogue
Emerging Issues Policy Forum
Critical Consumer Issues Forum
Department of Energy Southern Regional Energy Assurance Exercise
Center for Public Utilities at New Mexico State University Current Issues 2011
Public Utilities Research Center Annual Conference

Table 7.4-1 Emerging Issues Educational Sessions

- A system to alert the Commission to upcoming legislation, court ruling or federal entity ruling is in place to provide senior leadership with timely information to assist the Commission with its duties, as well as alerts related to happenings within the regulated industries. A total of nearly 900 alerts was issued during 2010-2011. These alerts are in the form of blog postings and emails. With new developments on the federal level concerning transmission, and proposed new EPA regulations and FCC rulings on horizon, the Commission desires to be proactive in response to issues that affect the entities they regulate (Chart 7.4-2).

- The Office of Advisory Staff and the Legal Department identified areas where the Commission needed additional training and conducted seminars on Act 175 of 2004, Perspectives on Water and Waste Water, and Proposed New EPA Regulations (Chart 7.4-2).

- In order to provide quality analysis, members of the Commission participated in webinars that featured outside experts [National Regulatory Research Institute (NRRI), Water Research Foundation, American Gas Association, Energy Central, EPA, FERC, and others] who addressed emerging utility issues (Chart 7.4-2).

- Participation in national and regional regulatory conferences (NARUC, SEARUC, NERC, IPU, etc.) and involvement in associated committees and related organizations benefited the commissioners and staff by keeping them informed of current and emerging issues within regulated industries (Chart 7.4-2).

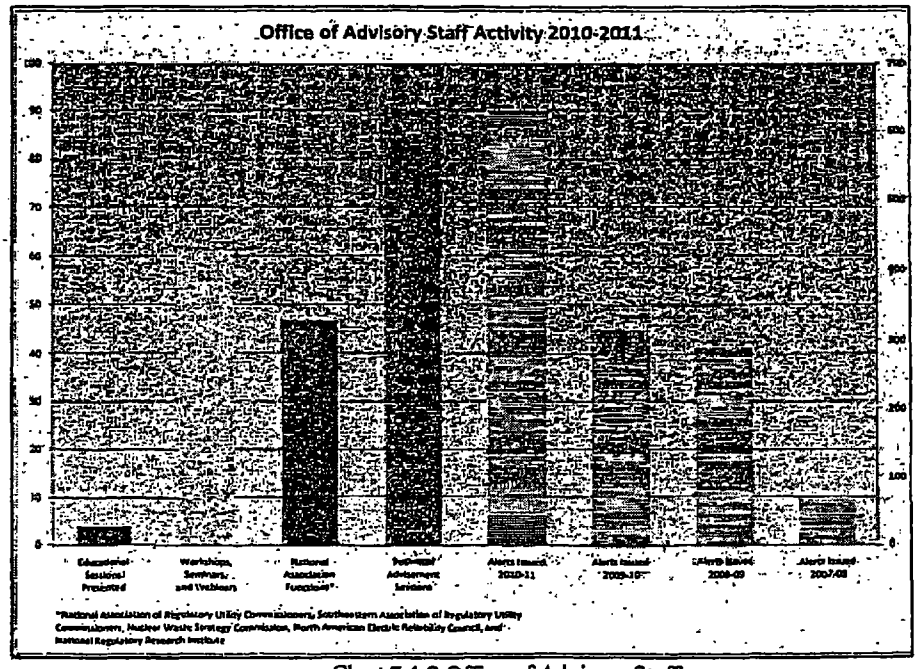


Chart 7.4-2 Office of Advisory Staff

- The commissioners and staff received training on ethics issues in the form of seminars and newsletters to ensure compliance with the Code of Judicial Conduct and Titles 8 and 58 of the South Carolina Code of Law.

- Commissioners and staff continued to achieve positions of leadership on the national level furthering the professional development of the Commission (Table 7.4-3). These positions cultivate the leadership of the Commission while ensuring that South Carolina and the Southeast's positions are represented on national issues such as transmission in the Eastern Interconnection, smart grid, gas pipeline safety, and broadband expansion.

First Vice President - NARUC Executive Committee*
Chairman - NARUC Committee on Gas*
Chairman - NARUC Committee on Water*
Chairman - NARUC Committee on Critical Infrastructure*
Chairman - NARUC Nuclear Issues and Waste Disposal Subcommittee
Chairman - Nuclear Waste Strategy Coalition
Chairman - NARUC Staff Subcommittee on Information Services
Secretary - Eastern Interconnection States Planning Council Executive Committee
Board Member - Universal Service Administrative Company
Board Member - Electric Power Research Institute
Voting Member - NERC Compliance and Certification Committee

* Additionally Serve on NARUC Board of Directors

Table 7.4-3 Leadership Positions

7.5 The Commission continued to identify improvements to operations and procedures that resulted in increased productivity.

- Electronic filing (E-Filing) of documents increases the timeliness of the information and improves productivity for the users and the Commission staff (Chart 7.5-1). As more users realize the benefits of E-Filing, the percentage of documents filed electronically will increase as the trend shows. E-Filing of documents on the ETariff System increased from 82% last year to nearly 90% this year.

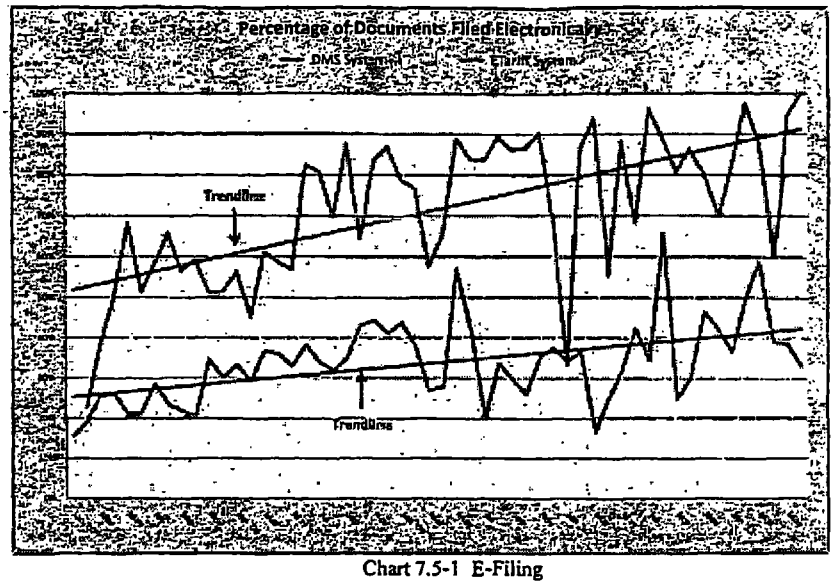


Chart 7.5-1 E-Filing

7.6 The process of revising the regulations that govern the practices and procedures of the Commission and its regulated industries is on-going (Table 7.6-1). In its 119th Session, the General Assembly approved the following revisions:

- Article 3 addresses customer deposits and retention of deposits for electric companies. The changes to Regulation 103-331 allow an electrical utility to require a deposit from a non-residential customer when the customer or its parent company is experiencing financial difficulties. With respect to Regulation 103-336, the revisions state an electrical utility is not required to refund a deposit if a non-residential customer or its parent company is experiencing financial difficulties. These revisions help electric utilities avoid losses and subsequent write-offs to uncollectible accounts.

- Article 6 revises bond requirements for local exchange telecommunications carriers. Revisions to Article 6 expand the present regulation of providers of prepaid local telephone service to all telephone utilities who provide retail residential local exchange services, but who have not invested at least five million dollars in telecommunications facilities in the State of South Carolina. The amendments also delete references to advance payments and prepaid payments and require bonds or other security mechanisms to be filed with the Commission and a copy provided to the Office of Regulatory Staff. These revisions will protect customers in the event a telephone company ceases to provide service.

A Notice of Drafting has been filed with the General Assembly's Legislative Council, and a public hearing has been scheduled for the following proposed regulation:

- Article 8 to create a new regulation to specify the information that must be submitted with electric utility financing applications filed with the Commission. Such additional information includes, but is not limited to, the effect of the proposed financing on the utility's income statement, balance sheet, and capital structure, and information on the possible impact on the utility if the proposed financing is not approved or if approval is delayed.

2010-2011 PSC Regulation Revision Status							
Article	Description	Notice of Drafting	Proposed Regulations Filed	Public Hearing Held	Final Regulations Filed	Approved by General Assembly	Published in State Register
3	Customer Deposits and Deposit Retention for Electric Utilities	✓	✓	✓	✓	✓	✓
6	Bond Requirements for Local Exchange Carriers	✓	✓	✓	✓	✓	✓
8	Requirements for Financing Applications for Regulated Electric Utilities	✓	✓				

Table 7.6-1 PSC 2010-2011 Regulation Review Process

********** END OF REPORT **********

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Legal Department
422 South Church Street
Charlotte, NC 28242-0001

DUKE POWER

704/382-8127

(704) 382-8137 Fax

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CHRISTIN J. BRAULETT
OF COUNSEL
WILLIAM T. WARD, JR.
GEORGE W. FERGUSON, JR.

October 25, 1991

OCT 23 1991
UTILITIES DIVISION

Mr. Charles W. Ballentine
Executive Director
The Public Service Commission
of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

Re: SCPSC Docket No. 91-216-E

Dear Mr. Ballentine:

Please find enclosed for filing in the above-captioned matter the original and 10 copies of the Proposed Order of Duke Power Company. Attached is a Certificate of Service for the parties of record.

Sincerely yours,

Ellen T. Ruff
Deputy General Counsel

ETR/sch
Enclosures
cc: Parties of Record
Mr. William F. Austin

S.C. PUBLIC SERVICE COMMISSION
RECEIVED
OCT 25 1991
RECEIVED

PETITIONER'S EXHIBIT

Printed on recycled paper

CERTIFICATE OF SERVICE

I hereby certify that I have this day mailed a copy of the Proposed Order of Duke Power Company (SCPSC Docket No. 91-216-E) to the following:

Ms. Marsha A. Ward, General Counsel
The Public Service Commission
of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

Mr. Steven W. Hamm, Consumer Advocate
Ms. Nancy J. Vaughn, Staff Attorney
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Columbia, South Carolina 29250-5757

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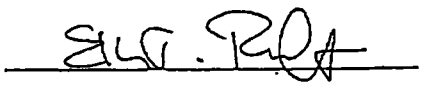
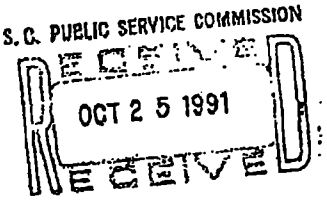
Columbia, South Carolina 29202-3200

Mr. William E. Booth, III
Mays, Foster, Booth & Gunter
2512 Devine Street
Columbia, South Carolina 29205

Mr. Jasper P. Rogers
Route 1, Box 346
Ridgeway, South Carolina 29130

This the 25th day of October, 1991.



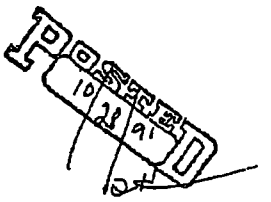


DE00009260

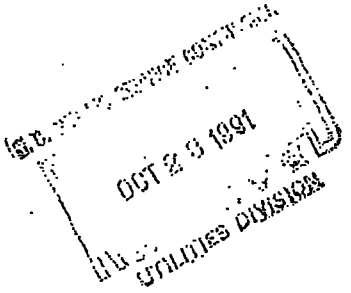
BEFORE THE

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 91-216-E



In the Matter of	)	
	)	PROPOSED ORDER
Application by Duke Power Company	)	OF
for Authority to Adjust and Increase	)	DUKE POWER COMPANY
Its Electric Rates and Charges	)	



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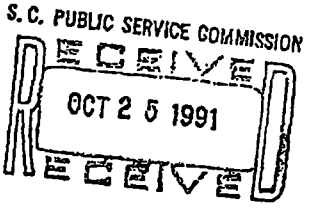

October 25, 1991

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On May 17, 1991, Duke Power Company (Duke or the Company) filed an Application with the Public Service Commission of South Carolina (the Commission) to adjust and increase its retail electric rates and charges, effective for service in accordance with the terms and conditions of §58-27-870, Code of Laws of South Carolina (1976), as amended.1/ The rates proposed by the Company in its Application were designed to increase annual gross revenues from South Carolina retail operations by $72,542,000 or 7.29% based on the test year, i.e., the twelve (12) months ended December 31, 1990.

The proposed revenue increase is distributed among classes of customers by increasing residential revenues by 9.08%, general service revenues by 7.96%, industrial revenues by 5.96%, and outdoor lighting revenues by 6.18%. Different percentage increases for customer classes are proposed because of the existing disparity in rates of return between customer classes.

The principal reason for the requested increase set forth in the Application is the commercial operation of the Bad Creek Hydroelectric Station, a 1,065 MW facility located in the mountains of western South Carolina. Units 1 and 2 began commercial operation on May 15, 1991. Units 3 and 4 began commercial operation on September 3 and September 13, 1991, respectively.

Petitions to intervene were received from the Consumer Advocate, South Carolina Department of Consumer Affairs, the South Carolina Energy Users Committee (SCEUC), the Clifton Power Corporation, and Jasper P. Rogers. These petitions to intervene were allowed by the Commission.

By letter of May 30, 1991, the Executive Director of the Commission required the Company to file with the Commission on or before June 24, 1991, and serve on all parties of record, the testimony and exhibits of the witnesses which the Company intended to offer at the hearing in this matter.

1/ Pursuant to the provisions of that section, the Company gave the Commission the statutory 30-day notice of its intention to file an increase in its rates.

DE00009263

By letter of June 11, 1991, the Executive Director of the Commission scheduled a public hearing on September 23, 1991, and required the Company to provide notice of the public hearing by newspaper notices and bill inserts. The Company furnished proof of publication of the required notice on July 19, 1991.

On June 24, 1991, the Company filed with the Commission its prepared direct testimony and exhibits for the following witnesses: William S. Lee, Chairman of the Board and President, Duke Power Company; Roger G. Ibbotson, President of Ibbotson Associates, Inc.; Richard J. Osborne, Vice President, Finance, Duke Power Company; Donald H. Denton, Jr., Senior Vice President, Planning and Operating, Duke Power Company; W. R. Stimart, Vice President, Rates and Regulatory Affairs, Duke Power Company; Ronald E. White, Senior Vice President, Foster Associates, Inc.; and Thomas S. LaGuardia, President, TLG Engineering, Inc. On September 3, 1991, Duke filed Supplemental Testimony and Supplemental Exhibit 1 of W. R. Stimart. Duke filed Supplemental Exhibit 2 on September 20, 1991. During the hearing, Duke filed Supplemental Exhibit 3.

By letter of August 8, 1991, the Executive Director of the Commission required the Commission Staff and all other parties of record to file their testimony on or before September 9, 1991. The following testimony was filed: for the Consumer Advocate: Paul Chernick, Resource Insight, Inc.; Peter J. Lanzalotta, Whitfield Russell Associates; Phillip E. Miller, Riverbend Consulting, Inc.; John B. Legler, Professor of Banking and Finance in the College of Business Administration, University of Georgia; for the Commission Staff: I. Curtis Price, III, A. R. Watts, and James E. Spearman; for the South Carolina Energy Users Committee: Nicholas Phillips, Jr.2/ The Commission also

2/ Pursuant to their respective requests, the Consumer Advocate and SCEUC were granted an extension of time to September 13 to file their testimony.

DE00009264

received a written statement from Jasper P. Rogers on or about September 21, 1991.

On September 16, 1991, Duke filed updated and revised testimony of Roger G. Ibbotson, and the Consumer Advocate filed a revised exhibit of Peter J. Lanzalotta.

On September 11, 1991, in Order No. 91-775, the Commission scheduled a prehearing conference for September 18, 1991, at 10:00 a.m. The prehearing conference was held as scheduled.

The public hearing before the Commission commenced as scheduled on September 23, 1991. William F. Austin, Esquire, Steve C. Griffith, Jr., Esquire, Ellen T. Ruff, Esquire, and Karol P. Mack, Esquire, represented the Company; Marsha A. Ward, Esquire, represented the Commission Staff; Steven W. Hamm, Esquire, Raymon E. Lark, Jr., Esquire, Nancy J. Vaughn, Esquire, and Richard Elam, Esquire, represented the Consumer Advocate; Arthur G. Fusco, Esquire, represented SCEUC; William E. Booth, III, Esquire, represented Clifton Power Corporation; and Jasper P. Rogers appeared on his own behalf. The public hearing was completed on September 26, 1991.

On September 25, 1991, the Company filed the rebuttal testimony of Donald H. Denton, Jr. and William F. Reinke. Subsequent to the hearing, the Consumer Advocate filed the surrebuttal testimony of Philip E. Miller and Paul Chernick on October 2, 1991.

A night hearing was held in Greenville, South Carolina on October 7, 1991. The Commission heard testimony from the following witnesses: Tom Blank, Jim Schumer, Earl Mills, Joe Jelks, Jim McKittrick, Ron Vankirk, John E. Newman, Robert Keenan, and Kris Risley.

Clifton Power Corporation was granted an extension of time to September 17 to file its testimony, but did not file any testimony.

Based upon the verified Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission now makes the following findings of fact:

FINDINGS OF FACT

General Procedural Issues

1. Duke is engaged in the generation, transmission, distribution, and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas.

2. Duke is an electric utility operating in the State of South Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. The Company's retail operations in South Carolina are subject to the jurisdiction of this Commission pursuant to S.C. Code Ann. §§58-27-10 et seq. (1976), as amended. The Company's wholesale operations in South Carolina are subject to the jurisdiction of the Federal Energy Regulatory Commission (hereinafter "FERC").

Test Period

3. The test period for purposes of this proceeding is the 12-month period ended December 31, 1990, adjusted for certain known and measurable changes.

Requested Increase

4. Duke, by its Application, sought an increase in its basic rates and charges to its South Carolina retail customers of $72,542,000. Subsequent to the filing of the Application, the Company lowered its request to $68,384,000.

Cost Allocation

5. The summer coincident peak (summer CP) demand allocation methodology is the most appropriate method for making jurisdictional allocation of production costs and for making fully distributed cost allocations among customer classes in this proceeding. Consequently, each Finding of Fact

appearing in this Order which deals with the overall level of rate base, revenues, and expenses for South Carolina retail service has been determined based upon the summer CP allocation method.

Test Period Revenue

6. The appropriate operating revenues for Duke for the test year under present rates and after accounting and pro forma adjustments are $994,450,000 for service to the South Carolina retail jurisdiction.

Bad Creek Hydroelectric Station

7. The Commission finds that the costs of the Bad Creek Hydroelectric Station were prudently incurred. In so doing, the Commission specifically finds that all four units were in commercial operation prior to the commencement of the hearing; that the station was completed under Duke's budget; that considering Duke Power's system generation needs, the choice of pumped storage was prudent compared to other types of generation such as combustion turbines; that Bad Creek is needed to enable Duke to meet the load on its system and to maintain a minimum level of reserve requirements; and that the Bad Creek Station is used and useful. The costs of the Bad Creek Station should be included in Duke's rate base.

Carolina Power & Light Co. Contract (Schedule J)

8. No adjustment to the test period for billings to Carolina Power & Light Company under Schedule J is appropriate.

Test Year and Post-Test Year Cost Increases

9. It is appropriate to increase operation and maintenance expenses by $4,832,000 to reflect increases in wage rates and related fringe benefit costs that occurred during the test year. This adjustment also results in a corresponding increase in payroll taxes of $419,000.

10. It is appropriate to increase operation and maintenance expenses by $4,287,000 to reflect increases in wage rates and related fringe benefits and payroll taxes which occurred after the end of the test year.

Implementation of SFAS 106

11. It is appropriate to increase operation and maintenance expenses by $3,830,000 to reflect the implementation of accrual accounting for other post-retirement benefits expense in accordance with Statement of Financial Accounting Standards No. 106.

Demand-Side Management Programs

12. The Commission Staff, the Consumer Advocate, and the Company entered a Stipulation relating to Demand-Side Management (DSM) cost deferral. The Stipulation is reasonable and is approved by the Commission.

13. It is appropriate to increase operation and maintenance expenses by $3,911,000 to reflect known increases in costs associated with the Company's load control and interruptible service demand-side management programs.

Depreciation and Decommissioning Expenses

14. The appropriate depreciation rates for purposes of setting depreciation expense are as follows:

Function	Rate
Production	
Steam	2.57%
Nuclear	
Decommissioning	1.61%
Investment	3.09%
Total Nuclear	4.70%
Hydraulic	1.98%
Other	0.74%
Transmission	2.57%
Distribution	3.59%
General (Summary Only)	3.59%

15. In determining decommissioning expense to be included in cost of service, it is appropriate to assume zero real return for qualified nuclear decommissioning trust investments and 1% for nonqualified investments.

16. The appropriate components of decommissioning expense to be included in cost of service are as follows:

(Dollars in Thousands)		Annual Cost	
Unit	Total Cost	System	S. C. Retail
Oconee 1	$164,792	$10,491	$ 2,722
Oconee 2	158,311	10,101	2,621
Oconee 3	202,855	12,218	3,171
Oconee ISFSI	21,750	1,325	344
McGuire 1	171,246	8,950	2,323
McGuire 2	186,265	9,294	2,412
Catawba 1	23,476	1,199	311
Catawba 2	26,163	1,271	330
TOTAL	$954,858	$54,849	$14,234

Other Operating Expenses

17. The reasonable level of test year operating revenue deductions for the Company after pro forma adjustments is $837,757,000.

Capital Structure and Rate of Return

18. The appropriate capital structure for the Company for use in this proceeding is as follows:

Item	Percent
Long-Term Debt	40.50%
Preferred Stock	9.68%
Common Equity	49.82%
Total	100.00%

19. The proper embedded cost rates for long-term debt and preferred stock are 8.78% and 7.74%, respectively.

20. The reasonable rate of return on common equity that Duke should be allowed an opportunity to earn is 13.17%, which the Commission adopts for this proceeding. Combined with the debt and preferred cost rates and the capital

structure set forth in the table below, which the Commission finds reasonable, the overall rate of return is 10.87%.

Item	Percent	Cost	Weighted Rate
Long-Term Debt	40.50%	8.78%	3.56%
Preferred Stock	9.68%	7.74%	.75%
Common Equity	49.82%	13.17%	6.56%
TOTAL	100.00%		10.87%

Material and Supplies

21. The reasonable allowance for materials and supplies investment is $73,668,000.

Plant Held for Future Use

22. The reasonable allowance for plant held for future use is $4,402,000.

Working Capital

23. The reasonable allowance for working capital is $57,832,000.

Rate Base

24. Duke's reasonable original cost rate base used and useful in providing service to the public within the State of South Carolina is $1,834,972,000, consisting of electric plant in service of $2,868,210,000; net nuclear fuel of $88,747,000; plant held for future use of $4,402,000; materials and supplies of $73,668,000; and allowance for working capital of $57,832,000, reduced by accumulated depreciation and amortization of $924,185,000, accumulated deferred income taxes of $315,569,000, operating reserves of $14,180,000, and customer deposits of $3,953,000.

Revenue Requirement

25. Based upon the foregoing, Duke should increase its annual level of gross revenues under present rates by $68,384,000. The annual revenue requirement approved herein is $1,062,834,000 which will allow Duke a reasonable

opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

Rate Design

26. The rate designs, rate schedules, miscellaneous charges, and terms and conditions proposed by the Company are appropriate and should be adopted, except as specifically modified herein.

27. The rate of return for the Industrial class is outside of the "band of reasonableness", a band or range of plus or minus 10% of the average retail rate of return. Consequently, the revenue increase approved herein should be distributed in order to move the Industrial class rate of return to the band of reasonableness.

28. The modifications to the penalty provisions of Interruptible Rider IS proposed by the Company should be adopted. The credit should not be increased in view of the substantial participation by customers at the current level of credit.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings concerning the Company's business and legal status is contained in the Company's verified Application and in prior Commission Orders in this Docket of which the Commission takes notice. These Findings of Fact are essentially informational, procedural, and jurisdictional in nature; and the matters which they involve are essentially uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings concerning the test period and the amount of the revenue increase requested by the Company is contained in the verified Application of the Company and the testimony and exhibits of Duke witnesses Lee and Stimart.

On May 17, 1991, the Company filed an Application requesting approval of rate schedules designed to produce an increase in gross revenues of $72,542,000.

Subsequent to the filing of the Application, the Company decreased its request to $68,384,000. The Company's filing was based on a test period consisting of the 12 months ending December 30, 1990. The Commission finds that this test period is appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding concerning the proper production allocation method consists primarily of the testimony and exhibits of Company witness Denton, Commission Staff witness Watts, and SCEUC witness Phillips.

Duke provides retail service in two states as well as wholesale service to certain municipalities and electric membership cooperatives; therefore, it is necessary to allocate the cost of service among jurisdictions and among customer classes within each jurisdiction. The Company based its Application on the use of the summer coincident peak allocation methodology (summer CP), which was found appropriate by the Commission in its order in the Company's last rate case, Docket No. 86-188-E. As Company witness Denton testified, Duke has utilized and the Commission has approved the summer CP method in its cost studies since 1970. Denton also testified that by all forecasts, Duke will continue to be a summer peaking company. (Tr. Vol. 2, p. 91)

Commission Staff witness Watts and SCEUC witness Phillips supported the continued use of the summer CP method. SCEUC witness Phillips presented testimony and exhibits demonstrating the dominance of the summer peak demand on the Duke system. Phillips further testified that other methods of cost allocation would not adequately account for the dominant summer coincident peak and would therefore fail to reflect the actual load characteristics of the Duke system. (Tr. Vol. 4, p. 112) No witness challenged the appropriateness of the summer CP allocation methodology for Duke.

The Commission finds, based on the evidence submitted by the Company, Staff, and SCEUC, that the summer coincident peak allocation methodology utilized by

Duke is most appropriate for Duke and therefore adopts the summer CP for cost allocation in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding concerning the adjusted level of operating revenues is found in the testimony and exhibits of Company witness Stimart, Commission witnesses Watts and Price, and Consumer Advocate witness Miller.

Company witness Stimart's exhibits reflected adjusted operating revenues under current rates of $994,450,000 for South Carolina retail operations. (Hearing Exhibit 4, Stimart Exhibit 1, page 1, Stimart Supplemental Exhibit 3, page 1) Commission Staff witness Watts agreed with the Company's ($1,004,000) adjustment to annualize revenues to the level of rates reflected in the currently approved South Carolina Retail tariffs. Watts also recommended that the Company's adjustment be modified by $110,510 to reflect the additional revenue associated with the requested increase in the Company's Reconnect Fee from $5.00 to $15.00. (Tr. Vol. 5, p. 229) The Commission finds that it is inappropriate to adjust test year revenues to reflect the proposed increased reconnect fee. The additional revenues to be derived from this proposal are part of the Company's requested increase of $68,384,000 and should be reflected as such.

Company witness Stimart adjusted test year revenue by $6,517,000 to reflect the expected annual level of KWh sales resulting from growth in the number of customers during the test period. (Hearing Exhibit 4, Stimart Exhibit 1, page 3) Mr. Stimart further testified that the end of period level of residential and general service customers was compared to the average number of customers during the test period. The increases in number of customers were then multiplied by the applicable average KWh consumption per customer to derive the annualized change in KWh consumption based on the number of customers at the end of the test period. (Tr. Vol: 2, pp. 145-146)

Commission Staff witness Price suggested that the standard Commission method of accounting for customer growth be utilized. (Tr. Vol. 5, p. 79) Consumer Advocate witness Miller also recommended using the procedure employed by the Commission in the Company's past cases. (Tr. Vol. 5, pp. 33-34)

The Commission notes that although the Staff and Consumer Advocate contend that they are using the standard approach to customer growth, they determined growth of .87% and .6927% respectively. (Hearing Exhibit 37, Accounting Exhibit A-2 and Hearing Exhibit 36, Schedule PEM5)

The Commission concludes that the Company's adjustment which is based on growth in specific customer classes and which utilizes average consumption by class is a more precise calculation than that proposed by either the Staff or the Consumer Advocate and is therefore appropriate for use in this proceeding.

The Commission finds that the Company's adjustment to annualize revenues to reflect the currently approved South Carolina retail tariffs is appropriate and should be adopted. The Commission also finds that Duke's recommendation for the customer growth adjustment should be adopted.

Based on the above findings, the appropriate level of operating revenues for the Company under present rates after accounting and pro forma adjustments is $994,450,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this Finding of Fact is contained in the testimony of Company witnesses Lee, Stimart and Reinke, and Consumer Advocate witness Lanzalotta. Mr. Lee testified that the Bad Creek Hydroelectric Station, a four-unit, 1,065 MW facility, was completed ahead of schedule and under budget. In his prefiled testimony, Mr. Lee testified that Bad Creek would be completed under budget at an approximate cost of $1.1 billion. (Tr. Vol. 1, p. 59) Mr. Lee testified that pumped storage offers special dynamic advantages to the Duke system that no other type of capacity can offer. Without Bad Creek, the

projected reserve margin in 1991 would have been well below the minimum reserve margin of 20%. (Tr. Vol. 1, p. 60)

In his summary and update of his testimony given on the stand, Mr. Lee stated that Bad Creek Units 1 and 2 went into commercial operation on May 15, 1991 and were in operation at the time of the record summer peak. If these two units had not been on-line, Duke's summer reserve margin would only have been 15%. Unit 3 began commercial operation on September 3, 1991 and Unit 4 on September 13, 1991. Mr. Lee testified that Bad Creek had been completed ahead of schedule and over $100 million under budget. He stated that the completed cost of Bad Creek compares favorably to other projects completed in the same timeframe. In addition, he testified that the capacity from Bad Creek is necessary to meet the growing demand for reliable electricity in the Duke service area and to maintain adequate reserve margins (Tr. Vol. 1, pp. 66-67)

Mr. Stimart, in the summary of his direct testimony, testified that the final plant cost of Bad Creek was approximately $1,008,000,000. (Tr. Vol. 2, p. 165)

Company witness Reinke also testified that Bad Creek Units 1 and 2 were needed to meet the summer 1991 peak and Units 3 and 4 are needed to keep reserves at the minimum levels in 1992. Duke's reserves are projected to be 20.7% in 1992 and 18.3% in 1993. (Tr. Vol. 6, p. 94)

Planning for Bad Creek began in the late 1960's when the Company foresaw the need for pumped-storage capacity to complement the nuclear and base load plants that were being planned and built by the Company. Mr. Reinke testified that pumped-storage projects such as Bad Creek offer benefits over and above the value of the capacity alone. Pumped storage is a benefit to the Duke system because its load shape can accommodate the technology and there is sufficient nuclear and fossil generation to provide low-cost pumping energy for Bad Creek. (Tr. Vol. 6, pp. 90-91) With the addition of Bad Creek, the Duke system will

be able to operate more reliably and economically because of the complimentary fit of the pumped-storage generation with the rest of Duke's generation. At a final cost of $1,008,000,000, Bad Creek compares favorably with other units of its type completed in the same timeframe. Exhibit (WFR-1), Hearing Exhibit 44, to Mr. Reinke's testimony, which assumes commercial operation in 1992, reflects this favorable comparison which is further enhanced by the fact that all four Bad Creek units were brought into operation ahead of schedule.

Consumer Advocate witness Lanzalotta was the only witness who raised any issues concerning the prudency of Bad Creek. Mr. Lanzalotta testified that there are indications that Duke has adequate pumped storage without the addition of Bad Creek. He testified further that his belief was based on his Exhibit (PJL-5), Hearing Exhibit 38, which showed that the generation from Duke's other pumped-storage generating unit, Jocassee, dropped by about 50% in 1992 and 1993, the first years of Bad Creek's operation. (Tr. Vol. 5, p. 119)

Company witness Reinke testified in response to this point and stated that the projected reduced output from Jocassee in 1992 and 1993 is the result of two of the Jocassee units being scheduled to be out of service for approximately six months in each year for major maintenance work. Mr. Reinke testified further that the addition of Bad Creek would enhance the opportunity to conduct the maintenance at Jocassee in the most economical way. (Tr. Vol. 6, pp. 92-93)

Witness Reinke testified that both the Jocassee and Bad Creek units operated above their projected levels of output in 1991. In addition he testified that the pumped-storage generation for the first 19 days of September, 1991, exceeded the total generation for Jocassee in September, 1990. (Tr. Vol. 6, p. 93) The Commission finds the evidence presented on this point by the Company to be convincing and rejects the position advanced by witness Lanzalotta.

Consumer Advocate witness Lanzalotta also testified that Units 3 and 4 of Bad Creek are not needed to maintain reliable reserves over the three-year

period during which Duke expects the rates from this proceeding to be in effect. Mr. Lanzalotta testified that with the addition of Bad Creek Units 3 and 4, Duke's reserves would range from 27.9% to 23.3% during 1991-1993. (Tr. Vol. 5, p. 125) This testimony was addressed by Company witness Reinke who showed that Mr. Lanzalotta had erred in the method he used to calculate Duke's reserves. The apparent discrepancy is in how demand-side programming should be treated in calculating reserve margins. Mr. Reinke testified that the proper method to calculate reserves is to determine the combustion turbine equivalent of demand-side management programs rather than as load, which is how Mr. Lanzalotta made his calculation. Mr. Reinke's testimony sets forth in some detail that where generating capacity is to be deferred or replaced by demand-side programs, it is appropriate to use a generation equivalent model to calculate reserves. Mr. Reinke testified that using this method, Duke's reserves would be 20.7% in 1992 and 18.3% in 1993 after the addition of Units 3 and 4 of Bad Creek. (Tr. Vol. 6, pp. 94-96)

The Commission is convinced by Duke's evidence and finds that Bad Creek Units 3 and 4 are required to maintain reliable reserves. In addition, the Commission specifically finds that Duke's methodology for calculating reserves as presented in its testimony is the proper method to use.

Company witness Reinke discussed the proper Minimum Planning Reserve margin in response to Mr. Lanzalotta's testimony concerning reserve margins. Mr. Reinke testified that the consideration of new demand-side programs and the long lead times required to construct major generating projects have made the matching of growth and the need for generating capacity even more imprecise. Because of these factors, it may well be prudent to increase the minimum planning reserve margin above 20%. (Tr. Vol. 6, pp. 96-97)

The Commission believes this approach has merit and finds that the Company will need to give special consideration to the impact of demand-side programs

in establishing its minimum reserve in accordance with its testimony in this case.

Consumer Advocate witness Lanzalotta offered testimony to show that 1,237 MW of combustion turbines would cost less in 1992 than Bad Creek. Mr. Lanzalotta used a bus bar analysis to show that 1,237 MW of CTs would be able to supply the same amount of capacity and energy expected from Bad Creek in 1992 at a total annual cost which is about $43,000,000 less than Bad Creek is expected to cost. Mr. Lanzalotta's analysis used a 5.8% capacity factor. (Tr. Vol. 5, p. 128)

Company witness Reinke testified in rebuttal to this point. Mr. Reinke testified that a bus bar analysis, which is simply the annual costs, including capital costs, of the plant divided by its annual output, is inappropriate as a means of comparing generating options with different characteristics. Such an analysis does not take into account the system benefits associated with pumped-storage such as the reduction in spinning reserve requirement and its load following capability. Mr. Reinke testified further that pumped storage is beneficial to the Duke system because its load shape is such that the pumped-storage generation can be utilized during the day to meet system load, and there are sufficient resources in the form of nuclear and efficient fossil generation to provide low-cost pumping at night and on the weekends. (Tr. Vol. 6, pp. 97-98)

Mr. Reinke testified further that Mr. Lanzalotta's use of a 5.8% capacity factor, which does not reflect the impact of the other system benefits of pumped storage in his bus bar analysis, was incorrect. In fact, Bad Creek has operated as high as 33.3% in 1991, and had numerous weeks when the capacity factor has been greater than 15%. Jocassee, Duke's other pumped storage hydroelectric generating station, has operated well in excess of 15% during 1991. A bus bar analysis using a 15% capacity factor rather than a 5.8% capacity factor, would

cost $10 million less annually than combustion turbines. (Tr. Vol. 6, p. 98) Similarly, a 27% capacity factor for Bad Creek produces a $79 million benefit annually over combustion turbines.

The Commission finds that, based on the evidence presented by the Company, Bad Creek provides greater savings to the consumer than an equivalent amount of combustion turbines.

Consumer Advocate witness Lanzalotta testified that the cost of Bad Creek was higher than the rates paid to co-generators. (Tr. Vol. 5, p. 127) Company witness Reinke testified in response to this point. Mr. Reinke stated that Mr. Lanzalotta's comparison was incorrect because it attempted to compare resources which have different operating characteristics. Mr. Reinke testified that co-generators and other QF's typically operate around the clock and fluctuate to meet the owner's requirements rather than Duke's system requirements. (Tr. Vol. 6, pp. 98-99) Mr. Lanzalotta acknowledged on cross-examination that one of the advantages of Bad Creek is that it will operate when the Company needs it. (Tr. Vol. 5, p. 171) The Commission finds that based on the evidence, a cost comparison of Bad Creek with co-generation is inappropriate.

After carefully reviewing all of the evidence presented by the parties, the Commission finds that the construction of Bad Creek was prudent and that it is needed to meet the demand in Duke's service area. The Commission finds further that the costs of constructing the station were prudently incurred and that the selection of hydroelectric pumped-storage generation is prudent compared to other generating alternatives. In addition, the Commission finds that Duke's reserve margins with the Bad Creek units in service will be at levels that are reasonable and necessary for reliable service.

The Consumer Advocate has criticized certain other aspects of Bad Creek. The Commission has reviewed this testimony and exhibits carefully. The

remaining criticisms, while not specifically addressed, must be rejected by the Commission as not being supported by the facts in evidence.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In Mr. Stimart's supplemental testimony, he recommended an adjustment to test period revenues to reflect the anticipated billings to be received under FERC Rate Schedule J between Duke Power Company and Carolina Power & Light Company. (Tr. Vol. 2, pp. 159-160) This adjustment would have decreased test period costs by $11,487,906. (Hearing Exhibit 4, Stimart Supplemental Exhibit 1, page 2) Mr. Lee testified on the stand, however, that Duke had received notice from Carolina Power & Light Company that it did not intend to comply with the provisions of Schedule J. He also testified that litigation could well result. (Tr. Vol. 1, p. 73) Based upon these events, Mr. Lee and Mr. Stimart recommended that no adjustment be made to the test period as a result of Schedule J due to the uncertainties involved in that contract. (Tr. Vol. 1, p. 74) (Tr. Vol. 2, p. 160) Mr. Stimart proposed that any collections received pursuant to Schedule J be placed in a deferred account and that when the uncertainty surrounding the contract is resolved, the Company submit a proposal to adjust rates to reflect the collections in the deferred account and to reflect future collections under Schedule J in rates. (Tr. Vol. 2, p. 160)

The Commission concludes that it would be inappropriate to include any amounts from Schedule J in rates adopted in this proceeding. The Commission orders the Company to place any collections received pursuant to Schedule J in a deferred account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Company and Consumer Advocate differed on the Company's adjustment to annualize the increases in wage rates and related fringe benefit costs during the test period. The Company proposed an adjustment of $4,832,000. Witness Price agreed with this adjustment. While witness Miller agreed with the

"concept of recognizing wage increases which have occurred during the test year", he opposed the Company's adjustment because of Duke Power's plans to reduce its workforce by three percent through attrition by the end of 1991. (Tr. Vol. 5, pp. 26-28)

Mr. Lee testified the three percent workforce reduction is the Company's expectation in an effort to identify all potential cost savings. He also testified that these efforts will not serve to reduce our cost of service but will serve to lower the level of increases. (Tr. Vol. 1, p. 53)

The Commission finds that witness Miller's proposed adjustment is inappropriate and inconsistent with the principles applied by this Commission. The effect of Duke Power's workforce plan on year-end wage expense and other expense levels is neither known nor measurable. The amount of wage increases granted during the test year is known and measurable and should be included in cost of service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The Company also made provision for the impact of cost increases on the Company's expenses occurring after December 31, 1990, which would be known and measurable at the time of the hearings in this proceeding.

At the hearing, Mr. Stimart identified actual wage increases of $4,287,000 and an actual increase in NRC fees of $1,048,000 that the Company had experienced since the end of the test year, December 31, 1990. Mr. Stimart testified that these cost increases are now known and measurable and should be considered by this Commission in determining the cost of service. (Tr. Vol. 2, pp. 166-167)

Staff witness Price recommended in his Supplemental Testimony the inclusion in cost of service of the additional NRC fees. Staff based its recommendation on its examination of the actual bills from the NRC which were furnished to the Staff and Consumer Advocate by the Company. (Tr. Vol. 4, p. 71) (Tr. Vol. 5,

p. 88) Consumer Advocate witness Miller did not address the additional NRC fees. Witness Miller did not take exception to the Company's adjustment to NRC fees as originally filed. In his direct testimony addressing attrition, witness Miller states that the Commission's current ratemaking philosophies mitigate against attrition by permitting "the annualization of various expenses to reflect changes which have occurred beyond the end of the test year, as long as the costs being used are known and measurable and reflective of normal, ongoing operations." (Tr. Vol. 5, p. 24). The Commission concludes that the additional NRC fees of $1,048,000 are an appropriate component of cost of service which has been audited by the Commission Staff and are a known and measurable ongoing expense.

In his Supplemental Testimony, Staff witness Price did not recommend the inclusion in cost of service of $4,287,000 for increased wages resulting from actual wage rate increases granted to employees during the period December 31 to July 31, 1991, because he did not have the opportunity to audit those wage increases. Witness Stimart explained on cross-examination that the workpapers were supplied to the Commission Staff and that the wage increase was calculated in the same manner as the adjustment for wage increases occurring within the test year which the Commission Staff accepted. (Tr. Vol. 4, pp. 71-72) The Consumer Advocate did not address this update in wage increases occurring after the test year.

The Commission concludes that the wage increases granted by the Company through July 31, 1991, meet the Commission's test of known and measurable. The Commission is mindful of the continuing effects of inflation on the Company's costs. Wage increases will continue to be granted in the months subsequent to July, 1991, and during the time the rates set in this proceeding are in effect. By including these known wage increases through July, 1991, in cost of service, the Commission is following its policies as outlined earlier by Consumer

Advocate witness Miller in order to give the Company a reasonable opportunity to earn the return this Commission allows.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

Consumer Advocate witness Miller recommended that Duke defer the costs associated with Statement of Financial Accounting Standards No. 106 (SFAS 106) because its effective date is not until 1993. (Tr. Vol. 5, p. 48) Company witness Stimart explained that SFAS 106 requires the Company to accrue, during the years that employees render the necessary service, the expected cost of providing those benefits to employees unlike the pay-as-you-go treatment afforded these benefits in the past. Witness Stimart testified that this Statement was effective in 1990 giving Companies some time to obtain the necessary records to adopt this statement as early as possible before the mandatory 1993 date. (Tr. Vol. 4, p. 62) The amount of the Company's adjustment is based on the cost determinations reflected in the Company's recently completed actuarial study undertaken to establish compliance with current accounting requirements. Commission Staff witness Price agreed with the Company's recommendation to recognize SFAS 106 costs in this proceeding particularly in light of the Company's recent major changes in retirement benefits. Price noted that the Company and Commission Staff have known for years that this expense was coming. (Tr. Vol. 5, pp. 92-94) This Commission approved the adoption of SFAS 106 in the GTE South Telephone case in Docket No. 90-698-C. (Tr. Vol. 5., p. 93)

The Commission finds that the Company's adjustment to reflect the implementation of SFAS 106 meets the known and measurable standard and is appropriately included in operating expense.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 AND 13

The evidence relating to Demand Side Management (DSM) costs and the DSM Stipulation is contained in the testimony of Company witnesses Lee, Denton,

Reinke, and Stimart; Consumer Advocate witnesses Chernick, Miller, and Lanzalotta; Commission Staff witness Watts; and SCEUC witness Phillips.

Pursuant to Docket No. 87-223-E, the Company, as well as other parties including the Consumer Advocate and Commission Staff, have agreed to comprehensive integrated resource planning procedures, including the requirement for utilities to submit by April 30, 1992, Integrated Resource Plans (IRPS) in accordance with the procedures agreed to and approved by the Commission therein.

Company witness Denton testified that the Company has been engaged in least cost planning since 1974 when the Company recognized the need for an alternative to building generation. (Tr. Vol. 6, p. 124) This planning process became more formalized in recent years and the least cost planning analysis produced a Least Cost Integrated Resource Plan in 1989 followed by two Short Term Action Plans which were submitted to the North Carolina Utilities Commission in 1990 and 1991. Duke will file the results of its current least cost planning cycle with this Commission in April, 1992. (Tr. Vol. 6, p. 125) Mr. Denton testified at length in his prefiled testimony and in his rebuttal testimony as to the comprehensive methodology used by Duke to assess the value of demand-side options as part of the least cost planning process. He testified that the purpose of the process is to select the most appropriate least cost alternative to meet future resource requirements. This is done by subjecting demand-side programs to a complex analysis, the results of which will be to create a blend of available options that will dependably and reliably meet customers' needs at the lowest reasonable cost. (Tr. Vol. 2, pp. 92-93) Witness Denton testified that all of the programs implemented by Duke for which Duke is seeking recovery have been stringently tested to ensure that they are cost effective. (Tr. Vol. 6, p. 127)

Company witness Reinke offered testimony to show how demand-side programs are evaluated as part of Duke's Short Term Action Plan to offset the need for generating capacity. (Tr. Vol. 6, p. 89)

Company witnesses Lee and Denton testified that the Company has accelerated its demand-side expenditures. These increased expenditures are included in cost of service in this case. (Tr. Vol. 1, p. 54; Vol. 2, p. 94) Mr. Stimart testified that test year expenses were adjusted to reflect incremental operating expenses for expansion of DSM programs. (Tr. Vol. 2, p. 151) Mr. Denton testified that the Company is seeking to recover incremental DSM costs of $6,475,000 in this case. (Tr. Vol. 2, p. 95) Commission Staff witness Watts reflected a similar adjustment in his analysis. Mr. Watts testified that the Staff had reviewed the demand-side programs, analyzed cost data from programs in effect in 1990, and concurs with Mr. Stimart's adjustment. These programs include many currently ongoing programs such as Residential Air Conditioning Load Control, Water Heater Load Control, Interruptible Service, Standby Generator, and Residential Off-Peak Water Heater Sales as well as an end-use research project. (Tr. Vol. 5, pp. 230-231)

Consumer Advocate witness Chernick testified that since the Company has not submitted its integrated resource plan for regulatory review, it has failed to establish that the plan is truly least cost. Mr. Chernick contends that the Company has provided no basis to evaluate the prudence of its demand-side program expenditures. Therefore, Mr. Chernick recommended that the $6,475,000 should not be recovered in rates in this proceeding until the Company could show the prudence of these costs. If the Company can demonstrate in this proceeding that certain of these expenditures can be prudently committed, then those costs may be approved for recovery through expensing, rate basing, and/or deferrals. For DSM costs that cannot be supported in this case, Mr. Chernick proposed that Duke file for Commission review at a later time. In addition, Mr. Chernick

testified that there were a number of features of the Company's DSM programs that were inconsistent with least-cost principles including: (1) the cost effectiveness of certain programs referred to as "load building", (2) the "lost opportunities" due to the way Duke structured its programs, (3) the possibility of cream skimming, and (4) rate design that encourages customers to "take back" their energy savings through increased consumption. (Tr. Vol. 5, pp. 182-186)

Following the submission of prefiled direct testimony, the Commission Staff, the Company, and the Consumer Advocate reached agreement on a Stipulation for recovery in this proceeding of DSM expenditures related to the Company's least cost plan. (Hearing Exhibit No. 45, Attachment B)

The Stipulation provides first, that the test year (1990) expenditures including advertising expense may be recovered as proposed by the Company in this proceeding. Second, $6.475 million of DSM costs for programs listed on page 15 of Mr. Denton's prefiled testimony actually incurred by the Company above the test year level may be booked by the Company into a deferred account. Advertising expenditures for these programs that are reasonable and designed to achieve the goals of the respective programs may also be booked into the deferred account. Further, the Company will credit the deferred account for found revenues to the extent lost revenues resulting from lost KWh sales due to DSM conservation programs are included in the deferred account. A return on the deferred balance will be computed monthly and added to the balance. The rate of return will equal the net of tax rate of return approved by the Commission in Docket No. 91-216-E or subsequent rate cases. The Stipulation provides further that if it is determined that the expenditures were prudent and for used and useful DSM programs, the balance in the deferred account will be reflected in the Company's next rate case or appropriate IRP docket by amortizing the then existing balance over a period of five years, except that

the Commission can order a different period if the amount in the deferred account would have a significant impact on rates.

Paragraph 8 of the Stipulation provides that the Commission may consider for inclusion in rates in this proceeding additional DSM costs that are actual and prudently incurred by the Company in 1991 attributable to the Company's Interruptible Service Program, Stand-by Generator Program, Water Heater and Air Conditioner Load Control Programs and associated advertising costs. These programs are listed on Appendix 2 to the Stipulation and amount to $3,910,814.

Finally, the Stipulation provides that although the parties have entered into the Stipulation, all relevant prefiled testimony, rebuttal and surrebuttal testimony, will be entered into the record as if given orally, and the parties will not cross-examine the witnesses on the testimony. Accordingly, rebuttal testimony was offered by Company witness Denton in response to points raised by Consumer Advocate witness Chernick and surrebuttal testimony was offered by Consumer Advocate witnesses Chernick and Miller.

In rebuttal testimony, Company witness Denton addressed each of the points raised by Mr. Chernick in his direct testimony. Mr. Denton testified that the load building programs referred to by Mr. Chernick and implemented by the Company have been stringently tested to ensure that they are cost effective. Mr. Denton testified further that these programs are cost effective because the marginal revenues exceed the marginal costs and therefore reduce rates for all customers. In particular, Mr. Denton testified that the Company's residential MAX program is not load building but rather is a program that combines high efficiency home insulation techniques with high efficiency heating and cooling equipment. Further, Mr. Denton explained that the dual fuel heat pump program utilizes a high efficiency unit to replace an existing cooling unit which will have a significant demand and energy reduction in the summer months. (Tr. Vol. 6, pp. 127-128)

With regard to the second point raised by Mr. Chernick -- "lost opportunities" --, Mr. Denton testified that the Company agrees with the principle of "lost opportunity" resources and includes this concept in its demand-side program design. In response to Mr. Chernick's concerns regarding the residential MAX program and high efficiency refrigerator and freezer programs, Mr. Denton testified that by specifying a total energy efficiency structure prior to construction, lost opportunities are eliminated. The high efficiency refrigerator and freezer program also makes use of opportunity resources by providing incentives at the time of purchase or replacement of existing units. Finally, Mr. Denton testified that the High Efficiency Heat Pump and Air Conditioning Incentive Program supports opportunity resources by providing a sliding scale rebate that directly provides the economic incentive to purchase the most energy efficient heating and cooling. (Tr. Vol. 6, p. 129)

Mr. Denton also offered testimony rebutting Mr. Chernick's concerns about "cream-skimming". Mr. Denton testified that DSM programs considered by Duke are evaluated for cost effectiveness through the least cost planning process. He pointed out that these programs are designed to maximize total KW and KWh reductions by taking into consideration anticipated customer participation. Mr. Denton concluded that Mr. Chernick was incorrect in his assertions concerning "cream skimming". (Tr. Vol. 6, p. 130)

Mr. Chernick's fourth area of concern dealt with what he called inappropriate conservation rate designs. He stated that Duke's pricing "fits poorly" with least cost planning. (Tr. Vol. 5, p. 211) Company witness Denton testified in rebuttal that Duke uses an established cost of service methodology for rate design which reflects the costs associated with serving customers in particular rate categories. (Tr. Vol. 6, p. 130)

Mr. Denton offered extensive testimony on the Company's least cost planning process. He stated that all DSM programs are stringently tested to ensure their

cost effectiveness. He testified further that all DSM dollars have been prudently spent according to the Company's Short Term Action Plan. (Tr. Vol. 6, pp. 131-132)

Consumer Advocate witness Chernick recommended disallowance of the costs associated with the Company's DSM pilot programs. (Tr. Vol. 5, p. 213) The Company disagreed with this position. Witness Denton testified that the seven pilot programs in place in 1991 are an expansion of these types of programs following the recommendations of certain DSM experts advising the NCUC Public Staff. Mr. Denton stated that these programs will provide important information that will reduce the costs of full scale implementation. Similar testimony was offered by Mr. Denton with regard to funds for evaluation procedures. Mr. Denton testified that such evaluation procedures were needed to ensure accomplishment of objectives for ongoing programs and to verify least cost planning accomplishments. (Tr. Vol. 6, pp. 133-134)

With regard to the Stipulation, witness Denton recommended that the Commission approve the deferred accounting provided for in the Stipulation so that the Company will not be penalized for prudent DSM expenditures. In addition, Mr. Denton testified that 1991 costs referred to in Appendix 1 of the Stipulation were actual costs incurred by the Company with regard to the interruptible service and load control payments that were in excess of the 1990 test year costs. Mr. Denton offered evidence to show that an additional $3,668,342 was incurred by the Company in 1991 with regard to the Interruptible Service and an additional $242,472 was incurred with regard to load control payments. Mr. Denton testified that these costs were actual and prudent and should be included in rates in this proceeding. He testified further that Standby Generator payments and advertising were at the same level as 1990 costs. (Tr. Vol. 6, pp. 134-137)

Mr. Denton testified that the Interruptible Service Program has 59 South Carolina industrial customers participating with monthly contract payments of $1,829 per MW. This program allows the interruption of 243 MW. In addition, 48,112 residential customers are participating in the load control program which allows the Company to interrupt 132 MW when there is a capacity shortage in the service area. The average monthly payment is $2,214. Mr. Denton testified that the Company compensates customers served by both the interruptible and load control programs under rate schedules approved by the Commission. Under the Standby Generator Program, 24 customers have contracted to provide 7.8 MW of generation during emergencies at an average monthly cost of $1,549. The Company pays these customers a rate approved by this Commission for actual generation. Finally, Mr. Denton testified that advertising is an essential element of these programs in order to communicate their availability. The costs of advertising are included in the cost benefit analysis of the program. With regard to all of these DSM costs, Mr. Denton testified that when customer payments in these programs are combined with other program costs, the program cost is less than the $5,100 per MW cost of a combustion turbine, the lowest cost source of equivalent supply side capacity. (Tr. Vol. 6, pp. 136-137) Company witness Reinke's testimony confirmed that these programs have been evaluated as part of the Company's Short Term Action Plan and offset generating capacity that would otherwise be needed. (Tr. Vol. 6, p. 89) Company witness Stimart reflected an adjustment of $3,911,000 as the amount to appropriately be included in rates based on Mr. Denton's testimony. (Hearing Exhibit 4, Stimart Supplemental Exhibit 3, page 3b)

Surrebuttal testimony was presented by Consumer Advocate witnesses Chernick and Miller addressing certain points in Mr. Denton's rebuttal testimony and certain issues raised by the Stipulation. Witness Chernick recommends that the Commission deny recovery of the 1991 actual incremental DSM expenditures in this

case and defer the costs until Duke documents its expenditures and demonstrates the prudency and cost effectiveness of the DSM programs. As a basis for this recommendation, Mr. Chernick states that Duke has failed to provide adequate evidence of the prudency of the 1991 expenditures. (Tr. Vol. 6, p. 151)

With regard to the load control programs, which include interruptible contracts, residential load control and standby generators, Mr. Chernick states that the Company has failed to adequately demonstrate that the costs of these programs are less than the cost of combustion turbine (CT) capacity. In addition, he states that the Company has failed to consider the effects of load control on the transmission and distribution system. Mr. Chernick also states that the fact that the load control programs are operated under Commission-approved tariffs does not mean that such expenditures are prudent. Finally, Mr. Chernick takes issue with what he states is the Company's failure to demonstrate the prudence of the evaluation and pilot programs and advertising. Witness Chernick recommends that all recovery of incremental DSM expenditures associated with these programs be deferred until the Company documents its expenditures and programs and demonstrates their prudence and cost effectiveness. (Tr. Vol. 6, pp. 146-151)

Consumer Advocate witness Miller testified that the $3,911,000 of 1991 DSM incremental costs should not be included in rates because the Company has provided no support for these costs even though the Consumer Advocate requested supporting workpapers. Therefore, Mr. Miller states that these costs are not known and measurable. (Tr. Vol. 6, p. 153) In a letter to the Executive Director of the Commission dated October 18, 1991, the Company stated there was no specific request for DSM workpapers. The Company further stated that the $3,911,000 was set forth in the Stipulation to which the Consumer Advocate agreed.

Duke, the Commission Staff, and the Consumer Advocate have submitted their Stipulation to the Commission for approval in this proceeding. No party has objected to approval of the Stipulation. The Commission has carefully reviewed the Stipulation and the testimony of the parties concerning the recovery of DSM costs. The Commission concludes that the Stipulation is reasonable and it is hereby approved. The Commission authorizes deferral accounting as requested in the Stipulation. The Company shall utilize Account No. 188, miscellaneous deferred debits, for the net deferral.

Although the Company, the Commission Staff, and the Consumer Advocate entered into a Stipulation, certain matters were left open for the Commission to decide. Paragraph 5 of the Stipulation provides for deferred accounting of up to $6,475,000 of incremental DSM expenses incurred above the 1990 test year level of expenses. This $6,475,000 was the amount included in the Company's original request for incremental DSM expenses. Paragraph 8 of the Stipulation provides that the Commission may include in rates additional DSM costs that are presented in Appendix 1 to the Stipulation and that it finds are actually and prudently incurred or prudently committed costs. Appendix 1 to the Stipulation identifies these costs as $3,668,342 for Interruptible Service credits and $242,472 for load control costs as discussed previously. Company witness Denton and Consumer Advocate witnesses Chernick and Miller have offered testimony on the prudency of the $3,911,000 expenditures. Commission Staff witness Watts recommended allowance of the $6,475,000 originally requested as an expense item and did not update the adjustment after the parties entered into the Stipulation.

The Commission has carefully considered the testimony and exhibits of each party. Based on the totality of evidence presented, the Commission finds that the $3,911,000 of 1991 DSM costs have been actually and prudently incurred and should be included in rates in this proceeding. Mr. Denton also testified that

these 1991 costs are ongoing and will continue to escalate. The more costs deferred now will only result in higher rates for future customers and a disincentive for DSM expenditures. Although Mr. Chernick and Mr. Miller contend that these costs were unsupported, Mr. Denton's testimony clearly showed that these 1991 costs were actually incurred by the Company in 1991. Therefore, they are known and measurable. These amounts were agreed to by the parties to the Stipulation, and no party reserved the right to cross-examine the Company with regard to these costs. Although Consumer Advocate witness Miller stated that the Company did not provide support for the DSM costs, this claim is not supported by the facts. Having reviewed the evidence of all of the parties, the Commission finds without merit the Consumer Advocate's arguments that the $3,911,000 were not known and measurable costs incurred by the Company.

With regard to prudency, the Commission finds that Mr. Denton's testimony with regard to the least-cost planning process and the fact that these DSM programs allow Duke to avoid capacity additions at a cost less than Duke could have built supply-side capacity is compelling on the question of prudency. Mr. Denton's extensive experience in the area of least-cost planning and DSM programs gives additional weight to his testimony on these matters. In addition, SCEUC witness Phillips testified specifically that the interruptible service credits included in these costs were too low. The Commission notes that the interruptible service credits and the load control credits, which comprise the $3,911,000 amount, are included in the tariffs of the Company previously approved by this Commission. Therefore, the Commission finds that based on the evidence presented by the Company and Mr. Phillips, the $3,911,000 incremental DSM costs are prudent and should be reflected in the cost of service in this proceeding.

The Consumer Advocate has challenged other features of Duke's DSM programs. The Commission has carefully reviewed this testimony and exhibits. The remaining objections and proposals, while not specifically addressed, must be rejected by the Commission. The Commission finds that the cost of DSM programs included in the test year and the incremental 1991 DSM costs are prudent and in the best interests of the customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 14, 15 AND 16

The evidence for these findings concerning the appropriate level of depreciation and decommissioning expense is contained in the testimony of Company witnesses Stimart, White, and LaGuardia, Commission Staff witness Watts, and Consumer Advocate witness Lanzalotta.

Duke adjusted depreciation expense to reflect its proposed depreciation rates and nuclear decommissioning expense. The Company based its proposed depreciation rates on a study prepared by Foster Associates, Inc. which is discussed in the testimony of Company witness Ronald White.

The following table sets forth the Company's current and proposed depreciation rates:

Function	Present	Proposed	Difference
Production			
Steam	3.57%	2.57%	(1.00%)
Nuclear			
Decommissioning	0.67%	1.61%	0.94%
Investment	3.33%	3.09%	(0.24%)
Total Nuclear	4.00%	4.70%	0.70%
Hydraulic	1.50%	1.98%	0.48%
Other	0.00%	0.74%	0.74%
Transmission	3.00%	2.57%	(0.43%)
Distribution	3.40%	3.59%	0.19%
General	5.48%	3.59%	(1.89%)
Total Utility	3.68%	3.69%	0.01%

This study also included the annual funding requirements of the nuclear decommissioning amounts based on the site specific decommissioning costs

studies included in Mr. LaGuardia's testimony. Commission Staff witness Watts testified that both the depreciation and decommissioning studies were reviewed by the Commission Staff and were just and reasonable and in line with the studies previously approved by this Commission. (Tr. Vol. 5, pp. 249-250)

Consumer Advocate witness Lanzalotta also reviewed the decommissioning study performed by Mr. LaGuardia. Mr. Lanzalotta testified that he did not propose any changes to the decommissioning costs developed by Mr. LaGuardia and noted that Mr. LaGuardia's costs were very much in line with the results of the Battelle decommissioning study funded by the Federal Government. (Tr. Vol. 5, p. 158)

The Company proposed in this proceeding to change its decommissioning expense for its nuclear reactors. Mr. Stimart testified that in the past a .67% rate for decommissioning was included in the Company's 4% nuclear depreciation rate. The Company proposed to change the decommissioning expense reflected in rates based upon current studies of the expected cost of nuclear decommissioning expense. The amounts in the study are based on the prompt dismantlement method of decommissioning because the Nuclear Regulatory Commission requires total funding of the contaminated components as of the date of termination of the operating license of each unit. In order to minimize costs, Duke decided to utilize a combination of internal and external funds to fund decommissioning. The Nuclear Regulatory Commission requires external funding for decommissioning the contaminated portion of each unit. The external fund amount is based on estimates contained in the site specific studies conducted by TLG Engineering, Inc. in 1989 and 1990 for each Duke nuclear unit. The external fund will be tax qualified to the extent possible under IRS rules and guidelines. The cost of decommissioning the rest of the plant will be funded internally and accrued based on a sinking fund methodology. (Tr. Vol. 2, pp. 147-148)

The study supporting the annual decommissioning expense is discussed in the testimony of Thomas LaGuardia. The following table sets forth the components of decommissioning expense included in cost of service in this proceeding:

(Dollars in Thousands)		Annual Cost	
Unit	Total Cost*	System	S.C. Retail
Oconee 1	$164,792	$10,491	$ 2,722
Oconee 2	158,311	10,101	2,621
Oconee 3	202,855	12,218	3,171
Oconee ISFSI	21,750	1,325	344
McGuire 1	171,246	8,950	2,323
McGuire 2	186,265	9,294	2,412
Catawba 1	23,476	1,199	311
Catawba 2	26,163	1,271	330
Total	$954,858	$54,849	$14,234

*1990 Dollars

All parties agreed with the Company's adjustment to use 1% real return for nonqualified nuclear decommissioning trust investments. The only area of difference between the Company and the Consumer Advocate relates to the appropriate real after tax return on funds invested in qualified nuclear decommissioning trusts. Consumer Advocate witness Lanzalotta proposed that Duke assume a 1.5% real after tax return on these funds instead of a zero real return assumption. Lanzalotta based his recommendation on a study of selected bond yields during the past ten years. (Tr. Vol. 5, pp. 134-140) On cross-examination of Lanzalotta, Duke presented evidence that, based on data from 1960 to 1988, no class of assets allowable for investment by qualified decommissioning trusts earned a real return as reported in a 1991 volume of The Energy Journal. Another study in the same volume reports that a zero real return assumption is "the only realistic alternative" for qualified fund securities. Returns on nonqualified funds should not be expected to be

significantly higher unless the utility accepts an amount of risk which is not appropriate for such funds. (Tr. Vol. 5, pp. 174-175) (Hearing Exhibit No. 42)

Mr. Stimart also testified that the Company will reassess its decommissioning provision every four years in order to consider changes in the estimate of the cost of decommissioning (including the effect of any life extensions granted to the Company by the NRC) and how well the decommissioning fund has performed. (Tr. Vol. 4, pp. 74-76)

Based on all the evidence, the Commission finds the Company's depreciation rates reasonable and approves the rates. The Commission also finds that it is appropriate to adopt the Company's annual decommissioning provision to include in cost of service. The Commission further finds that the Company's assumption of a zero real return on funds invested in qualified nuclear decommissioning trusts is reasonable and well supported by the evidence.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding concerning the reasonable level of test-year electric operating expenses is found in the testimony and exhibits of Company witnesses Stimart, White and LaGuardia, Commission Staff witnesses Price and Watts, and Consumer Advocate witnesses Miller and Lanzalotta. The Company proposed total electric operating expense of $837,757,000. 3/

The differences between the Company, the Commission Staff, and Consumer Advocate are summarized below:

3/ Unless otherwise specified, all numbers throughout the remainder of this Order are allocated as South Carolina retail.

Electric Operating Expenses

	Company	Commission Staff	Consumer Advocate
O&M Expenses:			
Fuel Used in Electric Generation	$197,625	$196,592	$196,592
Purchased Power and Net Interchange	141,680	141,680	130,192
Wages, Benefits, Materials, etc.	274,563	267,974	251,058
Depreciation and Amortization	121,499	116,895	119,855
General Taxes	48,755	42,122	46,091
Interest on Customer Deposits	468	474	468
Income Taxes	57,562	61,465	69,709
Amortization of ITC	(4,395)	(4,395)	(4,395)
Total Electric Operating Expenses	$837,757	$822,807	$809,570

O&M Expenses

The three categories of O&M expenses are fuel, purchased power and net interchange, and other O&M expenses, i.e., wages, benefits and materials. The Commission will discuss each area separately. The only difference between the Company, the Commission Staff, and Consumer Advocate with respect to fuel used in electric generation is related to the fuel expense derived from the Company's customer growth adjustment. This adjustment has been considered by the Commission previously. Having accepted the Company's proposed adjustment for customer growth, the Commission concludes that $197,625,000 is the appropriate level of fuel expense for use in this proceeding.

The difference between the Company and the Consumer Advocate with respect to purchased power expense is the 400 MW Schedule J sale to Carolina Power & Light Company. The Commission's findings concerning this item were previously discussed under Finding of Fact No. 8 and will not be repeated here.

Other O&M Expenses (Wages, Benefits, Materials, etc.)

The difference between the Company, Commission Staff, and Consumer Advocate with respect to other O&M expenses is summarized below:

(000's)

	Company	Commission Staff	Consumer Advocate
Wages, Benefits, Materials, etc.	$274,563	$267,974	$251,058
Difference		$(6,589)	$(23,505)

Analysis of Differences

1.	Disallowance of Test Year Growth and Inflation	$(3,796)	$(3,796)
2.	Post-Test Year Cost Increases:		
	NRC Fees		(1,048)
	Wage Increases	(4,287)	(4,287)
3.	Reclassification of Expenses as Nonelectric	(274)	
4.	Increase for Wage Rate Changes During the Test Year	--	(4,832)
5.	Removal of LES amortization	(616)	(574)
6.	Disallowance of Portion of Officers' Salaries	(180)	(15)
7.	Demand Side Management Costs	2,564	(3,911)
8.	Industry Association Dues	--	(469)
9.	Employee Moving Expense	--	(455)
10.	Advertising Expense	--	(110)
11.	Storm Damage Costs	--	(121)
12.	Lobbying Expense	--	(57)
13.	Implementation of SFAS 106	--	(3,830)
	TOTAL DIFFERENCE	$(6,589)	$(23,505)

Item 1. Test Year Growth and Inflation

Company witness Stimart proposed adjustments for growth and inflation during the test year. The Company made an adjustment of $859,000 to annualize O&M expenses other than fuel, purchased power, wages and benefits based on growth in customers during the test period. The Company also adjusted test period operating expenses, primarily operating materials and supplies, by $2,937,000 to reflect the continual rise in unit costs which occurred during the test period. This adjustment annualizes the effect of inflation which took

place throughout the test period. (Tr. Vol. 2, p. 150) Both Commission Staff witness Price and Consumer Advocate witness Miller proposed to disallow adjustments for test year inflation as not being known and measurable. (Tr. Vol. 5, pp. 25, 79-80)

Witness Stimart testified that this type of adjustment is necessary to make test period O&M expenses representative of the expenses which will be incurred while the proposed rates are in effect. (Tr. Vol. 2, p. 150) However, neither the Commission Staff nor the Consumer Advocate witness disputed the fact that inflation occurred both before and during the test period, and is likely to continue for years to come.

The Commission finds that the Company's adjustments for test year inflation and growth are appropriate. The objective of the test period is to be representative of the conditions expected to exist during the period of time the rates determined in this proceeding will be in effect. Various adjustments to the historical test year are made to accomplish this objective. The Commission acknowledges that inflation is and has been a "fact of life" in the modern economic environment. The level of inflation can be reasonably measured, and the Company's calculation of these adjustments is reasonable. The Commission believes it is necessary to reflect cost escalation in cost of service in order to present a representative picture of the conditions expected to exist during the time the rates approved in this Order will be in effect.

Item 2. Post-Test Year Cost Increases

The Commission's findings concerning this issue have already been discussed under Finding of Fact No. 10 and will not be repeated here.

Item 3. Reclassification of Expense as Nonelectric

Commission Staff witness Price eliminated certain actual cost of service items and reclassified them as costs to be borne by the Company's stockholders. Those costs include:

	(000's)
Payments to EEI for Media Communications	$ 64
Dues and Subscriptions	99
General Advertising	40
Recreation Expense	71
TOTAL	$274

As explanation for the adjustment, witness Price testified that the Commission has traditionally held that these types of expenses should not be ratepayer supported since they are not necessary to provide electric service. (Tr. Vol. 5, p. 80)

The Commission has adopted the Uniform System of Accounts which provides for costs of this nature to be supported by ratepayers as an electric expense. The Commission therefore rejects witness Price's adjustment. These costs are a necessary part of doing business and they are recorded in the proper accounts according to the Uniform System of Accounts. (Tr. Vol. 4, p. 87)

Item 4. Increase in Wage Rate and Fringe Benefits

The Commission's findings concerning this issue have already been discussed in Finding of Fact No. 9 and will not be repeated here.

Item 5. Louisiana Energy Services

The Company has included in its total Company per book figures $2,209,000 for the amortization of the Company's investment in Louisiana Energy Services (LES). The Company seeks recovery from South Carolina ratepayers of $616,000 in this case, which is South Carolina's portion of the amortization. Duke has

classified LES expenditures as research and development (R&D). (Tr. Vol. 1, p. 63)

LES is a partnership between a Duke subsidiary and four other entities. LES is exploring the construction and licensing of a uranium enrichment services technology that has not previously been utilized or licensed in this country. Presently the only provider of uranium enrichment services in the United States is the Department of Energy (DOE). (Tr. Vol. 1, pp. 63-65)

Mr. Lee testified that participation in LES was necessary in order for the project to be viable. The project would supply needed competition to the uranium enrichment services market which will lower the price of uranium enrichment services. Mr. Lee testified that the Department of Energy price is high compared to the costs of uranium enrichment services utilizing centrifuge technology such as LES would employ. In addition, Mr. Lee testified that Duke would receive a favorable uranium enrichment services contract if the LES project was successful. Finally, Mr. Lee testified that as a result of the potential competition provided by LES the Department of Energy had already lowered its uranium enrichment services prices. These lower prices more than offset Duke's total expenditures in connection with LES. (Tr. Vol. 1, pp. 63-65)

Commission witness Price recommended that LES costs be removed from the cost of service for South Carolina ratepayers for several reasons including the almost complete amortization of the LES costs as of the date of this hearing, the fact that the construction and operating licenses were not docketed by the NRC until May 15, 1991, the likelihood of no response from the NRC until late 1991, the uncertainty of the decision to proceed with the project unless reasonable financing is obtained, the possibility of reduced prices from the DOE with competitive pressure, Duke's lack of experience with this technology,

and the reduction in investment if Duke sells its interest in LES. (Tr. Vol. 5, pp. 85-86)

Consumer Advocate witness Miller recommended that LES costs be removed from test year operating expenses and set up in a deferred account because of the contingencies surrounding licensing, the decision to proceed to construction, and Duke's plans to sell or redeem its investment at the end of the venture period. (Tr. Vol. 5, p. 16)

The Commission finds that it is appropriate in this proceeding to amortize LES expenditures as proposed by the Company. No party has contested that these expenditures have been reasonably and prudently incurred and are for the benefit of Duke's customers. Furthermore, no party has challenged the research and development nature of these expenditures. There is no reason to treat LES expenditures any differently than any other research and development costs. The points outlined by Mr. Price further indicate the R&D nature of these expenditures as an attempt by the Company to seek innovative ways to supply electricity at least cost. Indeed, the evidence in this case indicates that Duke's present customers already are receiving benefits from LES expenditures because of the reduction of Department of Energy prices. The Commission continues to encourage R&D expenditures especially when there exists a strong potential to benefit electric customers.

Item 6. Officers' Salaries

Both Commission Staff witness Price and Consumer Advocate witness Miller proposed to eliminate the increases in officers' salaries for the test year in accordance with established Commission policy. Mr. Stimart testified that officers' salaries are already allocated to nonelectric operations. First, salaries are allocated to the extent officers can identify time spent on nonelectric business. Second, salaries are allocated to nonelectric through the application of the Massachusetts formula. (Tr. Vol. 4, p. 40)

Based on this evidence, the Commission determines a further allocation of officers' salaries is not required as proposed by Mr. Price and Mr. Miller.

Item 7. Demand-Side Management Stipulation

The Evidence and Conclusions for this item have previously been discussed under Findings of Fact Nos. 12 and 13. The Commission will not repeat that discussion here.

Item 8. Industry Association Dues

Duke included in cost of service dues for Edison Electric Institute (EEI) and the United States Council for Energy Awareness (USCEA). Consumer Advocate witness Miller proposed the elimination of these dues from test year operation and maintenance expenses based on his belief that these two associations' activities do not provide a direct and primary benefit to ratepayers. (Tr. Vol. 5, pp. 38, 44)

The Commission notes that EEI is recognized as a central source of authoritative information on electric energy and provides factual information to congressional committees and regulatory agencies. EEI's efforts have saved electric companies and their ratepayers millions of dollars thus directly benefitting South Carolina retail customers. Mr. Stimart testified that a portion of the EEI dues have already been recorded as a nonelectric expense. Each year EEI tells each of its member companies the portion of EEI dues not related to electric operations. The amount indicated in this letter is the result of audits and negotiations between the NARUC management and EEI. (Tr. Vol. 4, p. 59) As a result, EEI expenses for lobbying and certain media activities are not accounted for in electric utility operations.

The USCEA's activities are primarily related to nuclear energy. Its activities include the examination of generic issues related to nuclear power and the collection and publication of statistical and other information related to nuclear power. Duke and its customers rely heavily on nuclear power for the

reliable delivery of electricity. It clearly benefits the Company's customers to have a reliable source of information in the constantly changing nuclear environment. Based on the foregoing discussion, the Commission finds that witness Miller's adjustments for EEI and USCEA dues are inappropriate.

Item 9. Employee Moving Expense

Witness Miller proposed to adjust the test year costs associated with employee moves and relocations to reflect the average employee moving expense incurred over the 5-year period from 1986-1990 because of fluctuations in moving expense from year to year. Witness Miller explained "it is important that any abnormally low or high expenditure be normalized for rate making purposes in order that the test year expenditure will be as representative as possible of the expenses that are anticipated to be incurred during the time the rates will be in effect." (Tr. Vol. 5, p. 32) Witness Stimart testified on cross-examination that with the ongoing aggressive assessment of costs, the movement of the Company's workforce experienced in 1990 should continue at an even higher rate. He concludes that 1990 costs for employee moving expense are representative of the upcoming years. (Tr. Vol. 4, pp. 81 & 82) The Commission finds that witness Miller's proposed adjustment is not supported by any evidence indicating that the 1990 expense level is unrepresentatively high.

Item 10. Advertising Expense

Witness Miller proposed to exclude advertising expense associated with ads which he alleged were of a goodwill or image building nature, ads which are purportedly contributions to various organizations, and a single billing error in the month of December for which the Company received a credit for $135,857 in January, 1991. Mr. Miller contended that these advertising expenses do not provide a direct and primary benefit to the ratepayers. (Tr. Vol. 5, pp. 39-41) Mr. Stimart testified that these costs are a necessary part of doing business

and have been recorded in the proper electric operating expense account. (Tr. Vol. 4, p. 87)

This Commission has adopted the FERC Uniform System of Accounts for recording utility transactions. These advertising costs were recorded as an electric operating expense as prescribed by this accounting system and as such are an appropriate expense for cost of service.

Item 11. Storm Damage Costs

The Commission approved deferred accounting of storm damage costs incurred in 1989 with a five-year amortization. In 1989, Duke experienced two of the most devastating storms in its history, the largest being Hurricane Hugo.

Consumer Advocate witness Miller proposed to adjust the annual amortization of deferred storm damage costs by removing 10.2% of the amortization because the deferred costs include certain labor and associated benefits that Mr. Miller alleges were already included in base rates. (Tr. Vol. 5, pp. 50-51)

The Commission notes that witness Miller incorrectly calculated his adjustment to remove a certain amount of labor by using a jurisdictional allocation factor. The Company's cost of service for South Carolina retail includes storm damage amortization expense on a direct charge basis. Witness Miller acknowledged on cross-examination by the Company that use of a jurisdictional allocation factor is inappropriate when expenses have been directly assigned. (Tr. Vol. 5, p. 64)

Based on the evidence, the Commission finds that the Company's treatment of storm damage expense is appropriate.

Item 12. Lobbying

Witness Miller recommended that 50% of all Public Affairs Department expenses be excluded from test year operating expenses and charged below the line as lobbying. Miller contended that the portion of the expense charged below the line by the Company is not representative of the lobbying-related

efforts conducted by employees in the Company's Public Affairs Department. (Tr. Vol. 5, pp. 42-43)

Mr. Stimart testified that the Company charges employee wages and expenses to nonelectric while they perform their job with respect to lobbying. (Tr. Vol. 4, p. 53) This is in accordance with the Uniform System of Accounts. He further testified that the amount charged to nonelectric is greater than it should be because the Company assumes the employee is lobbying 100% of the time while the employee is in the state capital during legislative session. (Tr. Vol. 4, p. 54)

The Commission disagrees with the Consumer Advocate's lobbying adjustment. Legislation can materially affect utility costs. The Clean Air Act is an example. The Consumer Advocate would eliminate all costs incurred in the Company's attempt to "influence the passage, defeat or amendment of legislation of interest to the Company." The Company has already allocated costs to nonelectric operations for lobbying.

Item 13. Implementation of SFAS 106

The Commission's findings concerning this issue have been discussed under Finding of Fact No. 11 and will not be repeated here.

Depreciation and Amortization

The Company proposes depreciation and amortization expense of $121,499,000. The differences between the Company, Commission Staff, and Consumer Advocate are summarized below:

(000's)

	Company	Commission Staff	Consumer Advocate
Depreciation and Amortization	$121,499	$116,895	$119,855
Difference		$(4,604)	$(1,644)

Analysis of Differences

1.	Bad Creek Depreciation	$ (109)	$ 270
2.	Bad Creek Deferred Cost	(4,915)	955
3.	Decommissioning Expense	--	(2,869)
4.	Amortization of Coley Creek Costs	--	*
5.	Amortization of Catawba Costs	420	--
	Total Difference	$(4,604)	$ (1,644)

* Adjustment recommended but not reflected

Item 1. Bad Creek Depreciation

The first area of difference relates to the amount of Bad Creek dollars included in electric plant in service. The Company included all four units; however, Commission witness Price recommended that only the Bad Creek balance through August 31, 1991, be included in gross plant because the Commission Staff had not audited the Company's updated numbers. Because of the difference in plant balance, the Commission Staff and the Company recommended different amounts for depreciation expenses.

Consumer Advocate witness Lanzalotta recommended disallowance of operating costs related to Units 3 and 4 as excess capacity but did not reflect this reduction in any of his exhibits or those of Consumer Advocate witness Miller.

The difference between the Company and the Consumer Advocate results from witness Miller not adjusting his exhibits to consider the Company's update of Bad Creek Costs.

Based on the evidence, the Commission finds that it is appropriate to include $5,182,000 of depreciation related to Bad Creek in cost of service as proposed by the Company.

Item 2. Bad Creek Deferred Cost

	(000's)	
	Company	Commission Staff
	$6,649	$1,734
Difference		$(4,915)

This difference results from the Commission Staff's recommendation of a ten-year amortization of the deferred cost related to the commercial operation of Bad Creek. The Company included in cost of service a three-year amortization of these costs together with the carrying cost on the unamortized cost during this three-year period. (Tr. Vol. 2, p. 151) The Commission Staff recommends the unamortized balance be included in rate base in order to allow the Company to recover the carrying cost of the unamortized balance during their recommended ten-year amortization period.

Witness Miller made no adjustment to the Company's proposed adjustment (Tr. Vol. 5, p. 62) nor did witness Miller update his exhibits to reflect the lower deferred costs as updated by the Company.

The Commission takes notice of its approval of deferral accounting for the start-up costs of Bad Creek from the commercial operation dates to the effective date of new rates resulting from this proceeding. In order to reduce the carrying cost South Carolina customers pay, the Commission finds the Company's adjustment appropriate.

Item 3. Decommissioning Expense

The Commission's findings concerning this issue have already been discussed under Finding of Fact Nos. 14, 15, and 16 and will not be repeated.

Item 4. Amortization of Coley Creek Costs

Duke proposed amortization over five years of the abandoned Coley Creek costs. The Commission approved the Company's accounting treatment of Coley Creek costs in a letter to Company witness Stimart dated October 29, 1990, reserving further review in this proceeding. Consumer Advocate witness Miller recommended amortization of these costs over a ten-year period. The Commission Staff accepted the Company's five-year write off. (Tr. Vol. 5, p. 92) Mr. Stimart testified that this Commission has tended to amortize items of this nature over varying periods of time depending on the magnitude of the dollars to be amortized. (Tr. Vol. 4, p. 44)

The Commission finds that the Company's accounting treatment of Coley Creek costs is appropriate and approves a five-year amortization period.

Item 5. Amortization of Catawba Costs

The Commission Staff included in cost of service the annual amortization of the Catawba deferred costs. This results from prior Commission decisions to amortize the reasonable and prudently incurred Catawba deferred costs over a ten-year period. No other evidence was submitted by the parties.

Based on the evidence, the Commission finds that the appropriate level of expense for depreciation and amortization is $121,499,000.

General Taxes

The Company proposed $48,755,000 as the appropriate level of general taxes. The differences between the Company, Commission Staff, and Consumer Advocate are summarized below:

(000's)

	Company	Commission Staff	Consumer Advocate
General Taxes	$48,755	$42,122	$46,091
Difference		$(6,633)	$(2,664)
Analysis of Differences			
1. Bad Creek Property Tax		(38)	94
2. Customer Growth Adjustment		(26)	(26)
3. Reconnect Fee		1	--
4. Payroll Tax		--	(419)
5. Franchise Fee		(6,570)	--
6. Property Tax		--	(2,313)
TOTAL DIFFERENCE		$(6,633)	$(2,664)

Items 1-4. Bad Creek Property Tax, Customer Growth Adjustment, Reconnect Fee and Payroll Tax

Based on the Commission's previous determinations as to the appropriate adjustments for Bad Creek investment, customer growth, the Company's proposed increase in reconnect fees and increased wage rates, the Commission finds that the general tax adjustments related to these items proposed by the Commission Staff and Consumer Advocate are not appropriate.

Item 5. Franchise Fees

Commission Staff witness Watts recommended removal of franchise fees/municipal license fees as part of the Cost of Service Study, listed in General Taxes as Revenue Related Taxes. (Tr. Vol. 5, p. 235) Mr. Watts cited the Commission's decision in City of Spartanburg v. Public Service Commission of South Carolina, 281 S.C. 223, 314 S.E.2d 599 (1984) as support for his recommendation. These fees, imposed by certain municipalities, would only be charged to those customers living within the corporate limits of that municipality, therefore not affecting all ratepayers.

For purposes of the rates adopted in this Order, the Commission finds that the franchise fees/municipal license fees are to be included in base rates.

The Company shall remove these fees beginning in January, 1992. The Commission requires the Company to give notice to all customers concerning the removal of these fees from the cost of service. After this notice period, the Commission finds it appropriate to reduce base rates for removal of franchise fees/municipal license fees and include these fees as a separate line component on affected customers' bills effective with the first billing cycle in January, 1992.

Item 6. Property Taxes

The Company annualized test period property taxes on plant in service at December 31, 1990. Witness Stimart testified that property taxes for calendar year 1990 were assessed based upon property balances at the end of 1989. Likewise, property taxes for calendar year 1991 will be assessed based upon property balances at the end of 1990. This adjustment increases property tax expense in the test period to the year-end level of investment. The Company's calculation was based upon actual historically experienced changes in rates. (Tr. Vol. 2, pp. 151-152) Witness Price supported the Company's adjustment. Witness Miller supported the concept of annualizing property taxes to reflect the taxes related to property in service at the end of the test year. However, Miller alleged that the Company's proposed adjustment was not known and measurable because it was an estimate. (Tr. Vol. 5, p. 45)

The Commission determines that the Company's adjustment to annualize property taxes is appropriate and because it is based on end of year actual plant balances, it is based on known and measurable standards.

The Commission finds that the appropriate level of expense for general taxes is $48,755,000.

Interest on Customer Deposits

The Company proposed that the actual test year level of interest on customer deposits of $468,000 be reflected in the cost of service. Commission Staff

witness Price proposed to annualize interest on customer deposits. (Tr. Vol. 5, p. 86) The Commission is not persuaded by the evidence that it is necessary to make any adjustment to the actual test year level of interest on customer deposits. Therefore, the Commission finds that $468,000 is the appropriate level of interest on customer deposits to include in the cost of service.

Income Taxes

The positions of the Company, Commission Staff, and Consumer Advocate regarding income taxes are summarized below:

(000's)

	Company	Commission Staff	Consumer Advocate
Income Taxes	$57,562	$61,465	$69,709
Difference		$ 3,903	$12,147

The differences in the parties' positions regarding the appropriate level of income taxes are due to the different levels of operating revenues and operating expenses proposed by each party as well as the rate bases proposed by each party. Based on the Commission's previous decisions regarding each of these items, the Commission finds that the appropriate level of expense for income taxes is $57,562,000.

Amortization of ITC

All parties agreed on the Company's proposed level of ($4,395,000) for amortization of ITC, which the Commission determines is the appropriate level of expense.

Based on the entire record in this proceeding, the Commission concludes that the appropriate level of operating revenue deductions for use in this proceeding is $837,757,000, calculated as follows:

Operating Revenue Deductions
(000's)

O&M Expenses:	
Fuel	$ 197,625
Purchased Power and Net Interchange	141,680
Wages, Benefits & Materials	274,563
Depreciation and Amortization	121,499
General Taxes	48,755
Interest on Customer Deposits	468
Income Taxes	57,562
Amortization of ITC	(4,395)
Total Operating Revenue Deductions	$ 837,757

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence concerning the appropriate capital structure is presented in the testimony and exhibits of Company witnesses Lee, Osborne and Ibbotson, Commission Staff witness Spearman and Consumer Advocate witness Legler. In its Application, the Company utilized its actual per book capital structure as of December 31, 1990, consisting of 49.82% common equity, 9.68% preferred stock and 40.50% long-term debt.

Both Mr. Lee and Mr. Osborne testified that maintaining the Company's AA bond rating is a major financial goal of the Company and a key to the retention of the Company's credit worthiness and financial strength so that the Company can obtain new financing when necessary, in both good and bad capital markets. They testified that one of the most important determinants of the Company's bond rating is its coverage of fixed charges, and they pointed out that Duke's SEC interest coverage ratio is currently lower than it has been at any time since 1983. (Tr. Vol. 1, p. 56) (Tr. Vol. 2, p. 48) Mr. Osborne testified that maintaining the capital structure of the Company at approximately its present levels of common equity and long-term debt is necessary in order to enable the Company to maintain a fixed charges coverage ratio at a level necessary to retain its AA bond rating. He testified that the importance of maintaining

Duke's credit quality is shown by what occurred in the mid-1970's when Duke was unable to finance at all in difficult capital markets after its bond rating had dropped to a single A. This resulted in Duke having to stop work at certain construction projects which resulted in increased costs of those projects. He also pointed out that certain rating agencies have expressed concern about the negative trend in Duke's fixed charges coverage and have emphasized the importance of the outcome of this rate case on Duke's credit since Duke is approaching the lower limits of the AA rating. (Tr. Vol. 2, pp. 46-53)

Dr. Ibbotson also testified that, in his opinion, the capital structure of Duke as proposed in this proceeding reflects appropriate financial management and should be maintained. Dr. Ibbotson also stated that an increase in the amount of debt in Duke's capital structure would leave the overall weighted cost of capital unchanged in the long run because while the debt weight would increase, both debt and equity costs of capital would also increase. He pointed out that today's market is understandably very wary of companies with high leverage. (Tr. Vol. 3, pp. 27-29)

Consumer Advocate witness Legler noted that although the Company's equity ratio may appear to be high on the surface, the equity ratio closely approximates the average equity ratio for AA rated electric utilities as reported by Value Line. Legler also noted that the 1990 equity ratio reflects a slight decline from the equity ratio in 1988 and 1989. (Tr. Vol. 6, p. 10)

Having carefully considered all of the evidence, it is our judgment that Duke's actual capital structure, which it is proposing, is within reasonable bounds under all of the circumstances. The Commission finds and concludes that the appropriate capital structure for Duke for use in this proceeding is as follows:

Long-Term Debt	40.50%
Preferred Stock	9.68%
Common Equity	49.82%
	100.00%

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence concerning the proper embedded cost rates for long-term debt and preferred stock is presented in the testimony and exhibits of Company witnesses Lee, Osborne, and Ibbotson, Commission Staff witness Spearman and Consumer Advocate witness Legler.

The positions of the Company, the Commission Staff and the Consumer Advocate with respect to the embedded cost rates for long-term debt and preferred stock are as follows:

	Company	Commission Staff	Consumer Advocate
Long-Term Debt	8.78%	8.67%	8.78%
Preferred Stock	7.74%	7.53%	7.74%

The embedded cost rates proposed by the Commission Staff reflect an updating to June 30, 1991.(Hearing Exhibit 37, Accounting Exhibit A-5)

Upon review of the evidence, the Commission finds and concludes that the embedded cost rates as of December 31, 1990, as proposed by the Company and agreed to by the Consumer Advocate which are synchronized with the capital structure as of December 31, 1990, are appropriate for use herein. Accordingly, the Commission finds that the appropriate embedded cost rates for use in this proceeding are as follows:

	Embedded Cost Rate
Long-Term Debt	8.78%
Preferred Stock	7.74%

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding concerning the appropriate return on common equity is found in the testimony and exhibits of Company witness Ibbotson, Commission Staff witness Spearman, and Consumer Advocate witness Legler. A principal issue in any ratemaking determination involves the proper earnings to be allowed on the common equity investment of the regulated utility. In this proceeding, the Commission heard the expert testimony of three witnesses relating to the fair and reasonable rate of return on common equity for the Company.

This Commission has frequently stated that it adheres to no particular theory or methodology for the determination of a fair rate of return on common equity. (See, e.g., Order No. 85-841, at p. 56) Rather, we perceive our function as that of engaging in a careful and reasoned analysis of the evidence in a practical context. The record of the instant proceeding illustrates the use of several fundamental methods for the determination of the cost of equity capital by the expert witnesses for the Company, the Consumer Advocate, and the Commission Staff. Those methods include the discounted cash flow ("DCF") method, the capital asset pricing model ("CAPM"), the risk premium method, and the comparable earnings approach.

The evidence presented by the witnesses demonstrated an approach to their respective investigations within the parameters of the language of the United States Supreme Court in its decision in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), at 603:

> [T]he return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

While the independent studies of each witness, either implicitly or explicitly, commenced with those standards, the respective methods employed produced quite different results, presenting the Commission with recommendations ranging from 11.5% to 13.17%. The Commission must weigh the opinions of the expert financial witnesses as to the expectations of investors or the opportunity costs of equity capital in conjunction with the tangible facts of the entire record of the proceeding, including the observable financial condition of the Company. Southern Bell Telephone & Telegraph Co. v. Public Service Commission of South Carolina, 270 S.C. 590, 244 S.E.2d 278 at 282 (1978). In the final analysis, we must determine the credibility and probative value of the testimony of the expert financial witnesses and use our judgment to evaluate this evidence in regard to the cost of common equity.

Furthermore, the Commission cannot determine the fair and reasonable return on common equity for the Company in isolation. Rather, the Commission must carefully consider a variety of relevant factors, including identifiable trends in the market relating to the costs of labor, materials, capital, interest rates and inflation rates; comparisons of past earnings with present earnings and prospective earnings; the prices for which the Company's service must be rendered; the returns of other enterprises and the reasonable opportunities for investment therein; the financial policy and capital structure of the Company and its ability to attract capital; the demonstrable competency and efficiency of the Company's management; the inherent protection against destructive competition afforded the Company through the operation of the regulatory process and the competitive forces that are coming into being that have never been experienced before; general economic conditions; and the public demand for growth and expansion which is required to evaluate the construction program for the foreseeable future. The Commission must strike the balance among these complex and interrelated factors in the context of the record herein.

In its determination of a fair and reasonable rate of return, the Commission maintains the ultimate responsibility of setting the rates to be charged for the utility services provided by the Company. The exercise of that responsibility involves the balancing of the interests of the consumer and the investor. The Commission must gravely balance the interests of the consumer in regard to the price of utility service with the interests of the same consumer in regard to the reliability and adequacy of the supply of energy. The Commission has maintained these interests paramount throughout this proceeding. The Commission's determinations of the Company's revenue requirements and of the proper allocation of those revenues within the approved rate structure embodied in this Order reflect fairly and equitably the interests of those consumers expressed in the record before us.

Duke presented Dr. Roger G. Ibbotson, the Consumer Advocate presented Dr. John B. Legler, and the Commission Staff presented Dr. James E. Spearman to testify on the rate of return to be applied to Duke's common equity. These witnesses updated their prefiled testimony to reflect changes in the capital markets which had occurred after preparation of their testimony. Dr. Ibbotson's testimony was filed on June 24, 1991, and was prepared in February of 1991 and used data current at that time. Dr. Ibbotson updated his prefiled testimony in September 1991 and used data current at that time. Dr. Spearman's testimony was filed on September 23, 1991, and was based on data current as of that date. Dr. Legler's testimony was filed on September 9, 1991, and used data current as of that date. Dr. Legler updated his testimony on September 25, 1991, and used current data as of that date.

A summary of the respective recommended returns on common equity, as updated, is as follows:

PARTY	WITNESS	METHOD	RETURN ON COMMON EQUITY
Company	Dr. Ibbotson	CAPM	13.17%
Staff	Dr. Spearman	CAPM/DCF	12.0% to 12.5%
Consumer Advocate	Dr. Legler	DCF/CAPM	11.5% to 12.5%

The Company's witness, Dr. Ibbotson, recommended in his prefiled testimony a return on common equity of 13.75%. Prior to the hearing, Dr. Ibbotson updated his recommended return on common equity to 13.17% because of changes in market conditions occurring between the time he prepared his testimony and the time of the hearing. (Tr. Vol. 3, p. 35)

Dr. Roger W. Ibbotson is Professor of Finance at Yale University and President of Ibbotson Associates, a Chicago-based financial consulting firm. Dr. Ibbotson estimated Duke's cost of equity using the Capital Asset Pricing Model (CAPM) which defines the cost of equity to be equal to the sum of the rate of return on a riskless security plus an equity risk premium, which is an additional return for the risk of holding the particular security (in this case Duke Power's common stock). The risk premium is estimated by multiplying the beta (a measure of risk) of Duke's common stock by the additional return which an investor expects to realize by investing in a diversified market portfolio rather than in the riskless security. (Tr. Vol. 3, p. 12) For the riskless security Dr. Ibbotson used an average of recent yields on 20-year U. S. Treasury bonds, selected mainly because that maturity matches more nearly the horizon over which equity capital is committed to Duke Power Company. For his estimate of the expected equity risk premium of the market as a whole, Dr. Ibbotson used 7.1%, which was developed in Ibbotson Associates' Stocks, Bonds, Bills and Inflation 1991 Yearbook, and is the arithmetic average of the differences, or spreads, between the annual total returns on the stock market (represented by the S&P 500), and the average annual income returns on 20-year treasury bonds, over the period 1926 through 1990. (Tr. Vol. 3, p. 25) Dr. Ibbotson explained

that this period was used because it is the longest period for which there is good quality data, and that the use of the longest available period yields the best estimate of the risk premium because the risk premium is a random variable and therefore the accuracy of the estimate increases with the period over which it is measured. (Tr. Vol. 3, pp. 15-18) Using a risk-free rate of 8.55%, a beta for Duke of 0.65 and a market risk premium of 7.1%, Dr. Ibbotson concluded that the current required rate of return on equity for Duke Power Company is 13.17%, which includes no allowance for down markets or flotation costs. (Tr. Vol. 3, pp. 26, 31 & 32)

The Commission Staff's witness, Dr. Spearman, used two independent methods -- the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow Method (DCF) -- in arriving at his estimates of the cost of capital. Based upon these two methods, he recommended a rate of return on common equity in the range of 12.0% to 12.5%. (Tr. Vol. 5, p. 295) In his DCF analysis, Dr. Spearman utilized a dividend rate of $1.72 per share and a stock price of $29.25 to derive a yield of 4.9% and a growth rate of 5% to 6%. Dr. Spearman's DCF analysis which included several variations resulted in an expected cost of common equity of 10.34% to 12.01%. (Tr. Vol. 5, pp. 275)

Dr. Spearman's prefiled testimony indicated a rate of return in the range of 10.59% to 12.50% based on his analysis of the CAPM method. (Tr. Vol. 5, p. 293) Dr. Spearman qualified his rate of return testimony as being perhaps on the low side. He stated that a cost of equity approaching the high end of the range requires that the market returns maintain their long-term average and that the betas "may be understated". (Tr. Vol. 5, pp. 294-295)

The Consumer Advocate's witness, Dr. Legler, primarily used the DCF methodology. Based on a stock price calculated by averaging the prices of Duke stock for June - August, 1991, of $28.88 per share, dividends of $1.72 per share, and a growth rate of 5.0% to 6.0%, Dr. Legler arrived at a range of cost

of equity capital for Duke Power Company using the DCF method of 11.0% to 12.0%. Dr. Legler's risk premium method produced a rate of return range of 11.2% to 11.5%. His CAPM method indicated a range of 10.3% to 12.5%. In his prefiled testimony, Dr. Legler's recommended rate of return produced a range of 11.7% to 12.8%. From this he suggested a return on common equity of 12.25%. In his updated testimony his range was 11.5% to 12.5% with a midpoint of 12%, his final recommended rate of return on equity capital. (Tr. Vol. 6, pp. 48-49, 53)

The Commission has been presented with differing testimony and evidence with respect to the cost of common equity. As that is the case, it is therefore our responsibility to weigh and evaluate such evidence and reach a decision after applying our expertise and reasoned judgment. The Commission observes that there are a number of valid approaches to the cost of equity determination, but that, in the final analysis, the results of all these approaches are influenced by the judgments and assumptions of the witnesses. In this case, judgment plays a critical role, for the disparity between the recommendations of the witnesses in their use of the DCF method is not attributable to any fundamental difference in methodology, but rather to legitimate differences of opinion as to what data provides the best evidence of the cost of equity. This Commission must ultimately use its own judgment in evaluating the evidence presented by the witnesses.

It therefore becomes the Commission's responsibility to set a fair and reasonable rate of return on common equity from which can be derived the lawful rates for the Company for its retail electric operations. This responsibility must be discharged in accordance with statutory and judicial standards, and based upon the numerous factors identified herein, and applied in accordance with the informed judgment of the Commission.

In light of all the relevant evidence in the record of this proceeding, the Commission is of the opinion, and so finds, that a fair and proper range of

return on common equity is from 12.5% to 13.17%. The Commission further finds that a fair and proper return on common equity of 13.17% provides the opportunity to produce additional annual revenues of $68,384,000 for the Company's South Carolina retail electric operations, which the Commission finds fair and reasonable.

The Commission considers 13.17% to represent the reasonable expectation for the equity owner, and therefore, consistent with the standards of the Hope decision. The return found fair and reasonable is sufficient to protect the financial integrity of the Company, to preserve the property of the investor, and to permit the Company to continue to provide reliable service to present and future customers at reasonable rates.

The Commission is influenced that 13.17% is a reasonable rate of return for three (3) additional reasons. First, in the second quarter of this year regulatory Commissions have granted other electric utilities rates of return averaging 12.9%. Included in that figure is the 13% and 13.5% rates of return granted to Virginia Power and Appalachian Power by the Virginia Corporation Commission. (Tr. Vol. 5, p. 302) Second, the electric utilities with a double A bond rating earned, on average, in excess of 13% on equity over the last three (3) years. (Tr. Vol. 5, p. 304) These are comparable companies with which Duke must compete for capital. Third, this Commission granted Duke a 13% rate of return in its last general rate increase case. When that rate order was granted, the rates of return recommended by the Commission's Staff and the Consumer Advocate did not differ a great deal from the recommendations in this case. Since 1986, inflation has increased and Duke's interest coverage has decreased. (Tr. Vol. 2, p. 48) We believe that interest coverage is a significant financial indicator. Fixing a lower rate of return would likely cause a further decline, which this Commission does not believe should occur.

In arriving at a rate of return herein, the Commission is concerned only with the return to be earned on the common equity allocated to that portion of the Company's operations subject to the Commission's jurisdiction in this proceeding.

An important function of ratemaking is the determination of the overall rate of return which the utility should be granted. This Commission has utilized the following definition of "rate of return" in previous decisions, and continues to do so in this proceeding:

> For regulatory purposes, the rate of return is the amount of money earned by a regulated company, over and above operating costs, expressed as a percentage of the rate base. In other words, the rate of return includes interest on long-term debt, dividends on preferred stock, the earnings on common stock and surplus. As Garfield and Lovejoy have put it "the return is that money earned from operations which is available for distribution among the various classes of contributors of money capital. In the case of common stockholders, part of their share may be retained as surplus."
>
> Phillips, The Economics of Regulation, pp. 260-261 (1969).

The amount of revenue permitted to be earned by the Company through its rate structure depends upon the rate base and the allowed rate of return on the rate base. As discussed in the preceding section of this Order, the primary issue between the regulated utility and regulatory body most frequently involves the determination of a reasonable return on common equity, since the other components of the overall rate of return, i.e., dividends on preferred stock and cost of debt, are fixed. Although the determination of the return on common equity provides necessary component from which the rate of return on rate base can be derived, the overall rate of return, as set by this Commission, must be fair and reasonable.

The United States Supreme Court's landmark decision in Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), delineated general guidelines for determining the fair rate of return in utility regulation. In the Bluefield decision, the Court stated:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business generally.
>
> 262 U.S. at 692-693.

> We held in Federal Power Commission v. Natural Gas Pipeline Co....that the Commission was not bound to the use of any single formula or combination of formulae in determining its rates. Its ratemaking function, moreover involves the making of 'pragmatic adjustments' (cite omitted)...Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling (cites omitted).... The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case, that regulation does not insure that the business shall produce net revenues. (cite omitted) But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. (cite omitted.) By that standard the return to the equity owner should be commensurate with returns on investments in other

> enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.
>
> 320 U.S. at 602-603

The vitality of these decisions has not been eroded, as indicated by the language of the more recent decision of the Supreme Court in IN RE: Permian Basin Area Rate Cases, 390 U.S. 747 (1968). This Commission has consistently operated within the guidelines set forth in the Hope decision. See, also, Southern Bell, supra, 244 S.E. 2d at 280-3.

The rate of return which the Commission has herein found to be fair and reasonable should enable the Company to maintain and enhance its position in the capital markets. Patently, however, the Company must insure that its operating and maintenance expenses remain at the lowest level consistent with reliable service and exercise appropriate managerial efficiency in all phases of its operations. The Commission has consistently manifested its abiding concern for the establishment and continuation of efficiency programs on the part of its jurisdictional entities. By its Directive of August 27, 1974, the Commission urged the derivation of cost control studies, the adoption of cost reduction programs, and the elimination and reduction of costs "in all possible ways." The continued awareness of the potential efficacy of such programs and their implementation is consistent with the conscious national and State policies to limit the deleterious effects of inflation.

Company witness Lee described the considerable effort made by the Company to reduce its costs of construction and its operations and maintenance expenses. (Tr. Vol. 1, pp. 53, 54, 68-69) (Tr. Vol. 2, pp. 11-18) The Company's construction policies and programs have resulted in favorable comparisons with the construction costs of other electric utilities. In addition, the standards for the measurement of economical generating operations manifest that the

Company has generally demonstrated an ability to produce electrical energy in a measurably efficient manner.

The record of this proceeding indicates that the Company has generally undertaken its cost reduction efforts in the spirit of the Commission's Directive and consistent with our previous Orders, especially the Order in Duke's last rate case in 1986. Since that time Duke has eliminated more than 1,200 work positions and is on a program to eliminate about 600 positions per year over the next three years mainly through attrition. (Tr. Vol. 1, pp. 50-51, 53) The Commission feels that Duke is serious about cost savings. Nonetheless, the Commission cannot ignore the effect of the Company's increasing operating expenses. The Company and the parties before us may take notice of the fact that the Commission is not inclined to be completely satisfied with the cost reduction and efficiency programs of any jurisdictional utility. The Commission will continue to expect the Company to design and implement such programs in the future as an index of good management practice in the interests of its customers and of the Company itself. With the full array of its resources at its disposal, the Company should be able to assure us that such programs produce identifiable and measurable results consistent with the provision of economical and adequate service to the Company's ratepayers. The Commission has found a fair and reasonable return on common equity which the Company should be allowed the opportunity to earn, and has herein set rates to produce revenues to reach that return. The Commission considers that effective programs of cost reductions can operate to enable the Company to improve its financial posture and earn the return approved. In addition to the review of the Company's cost of service in the context of this proceeding and our express expectations of efficient and effective management, the Commission considers the accepted regulatory devices of the use of a year-end rate base, adjustments for customer growth and annualized depreciation, together with adjustments for identifiable

and measurable changes in revenues and expenses to combine to represent a reasonable regulatory approach to the earnings erosion attributable to inflation.

The Commission has found that the capitalization ratios as of December 31, 1990, are appropriate and should be used in the instant proceeding. The Commission has likewise found that the respective embedded cost rates for long-term debt of 8.78% and for preferred stock and preference stock of 7.74%, should be utilized in the determination of a fair overall rate of return. For the purpose of this proceeding, the Commission has herein found the proper cost rate for the Company's common equity capital to be 13.17%.

Using these findings, the overall fair rate of return on rate base for the Company's South Carolina retail electric operations may be derived as computed in the following table:

OVERALL RATE OF RETURN

	Rate	Cost	Weighted Cost
Long-Term Debt	40.50%	8.78%	3.56%
Preferred Stock	9.68%	7.74%	.75%
Common Equity	49.82%	13.17%	6.56%
TOTAL	100.00%		10.87%

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 21

This evidence pertaining to the proper amount of materials and supplies investment is found in the testimony of Company witness Stimart. The Company proposed that $73,668,000 be included for materials and supplies, consisting of $25,495,000 of fuel stock and $48,173,000 of other electric materials and operating supplies as presented on Hearing Exhibit 4, Stimart Exhibit 1, page 4c. No party challenged the reasonableness of this figure. The Commission finds that the proper total materials and supplies investment is $73,668,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence pertaining to the proper amount of investment for plant held for future use is found in the testimony of Company witness Stimart. As shown on Hearing Exhibit 4, Stimart Exhibit 1, page 4, the Company proposed that $4,402,000 be included in rate base to reflect investment in plant held for future use. No party challenged this figure. The Commission therefore finds it appropriate to include $4,402,000 in rate base for plant held for future use.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence related to the proper working capital investment is contained in the testimony of Company witness Stimart, Commission witness Price, and Consumer Advocate witness Miller. An analysis of the total working capital investment proposed by the parties is set forth in the following table:

Working Capital Investment

(000's)

	Company	Commission Staff	Consumer Advocate
Operating Funds	$48,489	$48,489	$48,489
Average Taxes Accrued	(16,366)	(16,366)	(16,366)
Bank Balances	2,120	2,120	700
Bond Reacquisition Premiums	10,906	10,906	7,890
Prepayments	2,839	2,839	2,839
Miscellaneous Deferred Debits and Credits	9,844	-0-	-0-
Deferred Costs	-0-	17,448	-0-
Total Working Capital	$57,832	$65,436	$43,552
Difference		$ 7,604	$(14,280)

The Company computed the cash component (operating funds) of working capital using the Commission's formula method which reflects 1/8 of operation and maintenance expenses exclusive of purchased power and nuclear fuel expense. This amount is then reduced by the average tax accrued balance. No party

contested this component of working capital or the prepayments of $2,839,000 included in working capital investment. The Commission concludes therefore that the amounts proposed by the Company for operating funds, taxes accrued, and prepayments are appropriate for use in this proceeding. The following components of working capital are in dispute:

Analysis of Differences

(000's)

	Commission Staff	Consumer Advocate
1. Miscellaneous deferred debits and credits	$(9,844)	$(9,844)
2. Bad Creek Deferred Costs	15,607	-0-
3. Catawba Deferred Costs	1,841	-0-
4. Required Bank Balances	--	(1,420)
5. Bond Reacquisition Premiums	--	(3,016)
Total Difference	$ 7,604	$(14,280)

Item 1. Miscellaneous Deferred Debits and Credits

The Company proposed that $9,844,000 be included in working capital for miscellaneous deferred debits and credits. Consumer Advocate witness Miller made an adjustment to exclude this component of working capital from rate base. Commission Staff witness Price did not include miscellaneous deferred debits and credits as a per book item of working capital.

The Staff did not provide any testimony supporting its exclusion of miscellaneous deferred debits and credits from the working capital investment included in rate base.

In support of his adjustment, Consumer Advocate witness Miller testified that such items are more appropriate for inclusion in a lead-lag study. (Tr. Vol. 5, p. 12) Witness Miller's opinion as to the appropriate treatment of deferred debits and credits in a lead-lag study, with no discussion of his reasoning, does not provide sufficient evidence to support his adjustment.

Likewise, his statement that the Commission does not regularly include deferred debits and credits in working capital investment provides no evidence that these items are not appropriate for inclusion in rate base in this proceeding. No party has offered evidence in this proceeding as to why the particular miscellaneous deferred debits and credits included in working capital by the Company are inappropriate for rate base inclusion in this proceeding. The Commission's decisions in prior cases were specific to the items of miscellaneous deferred debits and credits presented in those proceedings. The Commission is aware that the components of miscellaneous deferred debits and credits change over time. Therefore, any party taking exception to the inclusion of such items in rate base must present evidence regarding the specific items proposed to be included in rate base. No party has provided such evidence in this proceeding.

The Commission finds that $9,844,000 of miscellaneous deferred debits and credits is appropriately included in working capital.

Item 2. Bad Creek Deferred Costs

The difference between the Company and Commission Staff on this item relates to different proposals regarding the recovery of return during the amortization period of the Bad Creek deferred costs. The Company calculated a levelized annual amortization which included a return component based on a three year amortization period. The Staff proposed that the deferred costs be amortized over ten (10) years and that the unamortized balance be included in rate base. (Tr. Vol. 5, p. 81)

The Commission has already determined in the Evidence and Conclusions for Finding of Fact No. 16 that a three-year amortization period for the Bad Creek deferred costs is appropriate. Further, the Commission determined that it was appropriate to calculate a levelized amortization which includes a return component, rather than to include an unamortized balance in rate base. This

treatment recognizes and accounts for the fact that the unamortized balance will decline over time. Inclusion of the unamortized balance in rate base, especially in conjunction with a ten-year amortization period, would overstate the Company's ongoing cost of service. Such a situation can only be resolved by annual rate changes or by use of a levelized amortization as proposed by the Company. The Commission concludes, therefore, that the unamortized Bad Creek deferred costs should not be included in rate base in this proceeding.

Item 3. Catawba Deferred Costs

Commission Staff witness Price has included $1,841,000 of unamortized Catawba deferred costs in working capital. This adjustment corresponds to his proposal to reflect the Catawba deferred costs amortization in the cost of service. (Tr. Vol. 5, p. 86, Hearing Exhibit 37, Accounting Exhibit A-3)

Based on the Commission's prior discussion concerning Bad Creek deferred costs, the Commission rejects this adjustment.

Item 4. Required Bank Balances

The Company proposed to include bank balances of $2,120,000 in working capital. The Commission Staff did not dispute this proposal. Consumer Advocate witness Miller disagreed with the Company's inclusion of end-of-period cash balances held in each account. Miller contended that if no adjustment were made, the Company would earn carrying costs on all cash on hand even though not all of that cash is required to maintain minimum and compensating balances and to meet daily cash requirements. Miller recommended that the amount included be limited to compensating balance requirements, working funds needed for daily operations, and miscellaneous special deposits. (Tr. Vol. 5, p. 13)

The Consumer Advocate attempted to show through cross-examination of Mr. Stimart that the cash in banks over and above the approximately $508,000 required as compensating balances is not appropriately included in cash working capital. (Tr. Vol. 4 at pp. 66-69) In support of its position, the Consumer

Advocate presented Hearing Exhibit 30, copies of portions of data responses provided to the North Carolina Public Staff. Mr. Stimart acknowledged that Hearing Exhibit 30 was a Company provided response, but he did not know what the question was. (Tr. Vol. 4, p. 68) The Commission is not persuaded by the Consumer Advocate's testimony regarding this issue. Further, the Commission cannot rely on portions of data responses provided in another jurisdiction without having access to the entire question and answer as well as all other related questions and answers which may have been raised regarding that issue.

The Commission finds Mr. Stimart's testimony regarding the necessity of having cash balances in the magnitude of $6,000,000 in view of the $4 billion worth of activity at its banks annually to be reasonable. (Tr. Vol. 4, pp. 68-69)

Based on the foregoing, the Commission finds that it is appropriate to include bank balances of $2,120,000 in working capital investment in rate base.

Item 5. Bond Reacquisition Premiums

The Company included $10,906,000 for bond reacquisition premiums in its working capital investment. (Hearing Exhibit 4, Stimart Exhibit 1, page 4c) The Commission Staff did not take exception to the Company's position. Consumer Advocate witness Miller proposed to adjust this amount in order to allocate a portion to nonelectric operations. Miller contended that reacquisition of bonds benefits all of the Company's operations, not just electric. (Tr. Vol. 5, p. 14)

Mr. Stimart testified that the bonds in question were issued to finance electric operations. (Tr. Vol. 4, p. 65) The Company's treatment of this item is consistent with past Commission practice in Docket Nos. 86-188-E and 85-78-E. The Consumer Advocate's reference to portions of testimony presented in the Company's North Carolina rate case does not constitute sufficient evidence in this proceeding on which the Commission can rely. (Tr. Vol. 4, pp. 65-66) The

Commission would have to have all pertinent evidence from the North Carolina proceeding in the record in this proceeding. The Consumer Advocate made no such offer of evidence in this proceeding.

The Commission finds that the treatment of bond reacquisition premiums proposed by the Company and agreed to by the Commission Staff is appropriate. Therefore, $10,906,000 of bond reacquisition premiums should be included in working capital investment.

Thus, the Commission concludes that the appropriate allowance for working capital for use in this proceeding is $57,832,000, as set forth in the table below:

Working Capital Investment	
Operating Funds	$48,489,000
Average Taxes Accrued	(16,366,000)
Bank Balances	2,120,000
Bond Reacquisition Premiums	10,906,000
Prepayments	2,839,000
Miscellaneous Deferred Debits and Credits	9,844,000
Total Working Capital Investment	$57,832,000

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding concerning the proper value for rate base is found in the testimony of Company witness Stimart, Staff witnesses Price and Watts, and Consumer Advocate witness Miller.

The difference between the Company, the Commission Staff, and the Consumer Advocate concerning rate base is summarized below:

	Rate Base (000's) Company	Commission Staff	Consumer Advocate
Electric Plant in Service	$3,390,362	$3,384,892	$3,404,002
Less:			
Accumulated Depreciation and Amortization	(1,357,590)	(1,357,607)	(1,357,860)
Net Electric Plant	2,032,772	2,027,285	2,046,142
Materials and Supplies	73,668	73,668	73,668
Plant Held for Future Use	4,402	4,402	4,402
Working Capital Investment	57,832	65,436	43,552
Less:			
Accumulated Deferred Taxes	(315,569)	(315,569)	(315,569)
Operating Reserves	(14,180)	(14,180)	(14,180)
Customer Deposits	(3,953)	(3,953)	(3,953)
Unclaimed Funds	-0-	-0-	(214)
Construction Work in Progress	-0-	-0-	-0-
Total Rate Base	$1,834,972	$1,837,089	$1,833,848
Difference		$2,117	$(1,124)
Areas of Difference			
1. Electric Plant in Service		$(5,470)	$13,640
2. Accumulated Depreciation and Amortization		(17)	(270)
3. Working Capital Investment		7,604	(14,280)
4. Unclaimed Funds		-0-	(214)
Total Difference		$ 2,117	$(1,124)

Item 1. Electric Plant

The difference between the Company, the Staff, and the Consumer Advocate regarding this item stems from the difference in the amount of Bad Creek included in plant in service. The Commission has already determined the prudency of all four units of Bad Creek in the Evidence and Conclusions for Finding of Fact No. 7. The issue remaining to be decided is the appropriate cost of Bad Creek to include in rate base.

The Company originally proposed an adjustment of $275,391,000 (Hearing Exhibit 4, Stimart Exhibit 1, page 4a) to reflect all four units of Bad Creek in electric plant in service. The Staff originally included $238,765,000 for Units 1, 2, and 3 in electric plant in service and included $17,640,000 for Unit 4 in construction work in progress. (Hearing Exhibit 37, Accounting Exhibit A-1, p. 9 of 9) The Staff's reasoning was that Units 1, 2, and 3 were all that could reasonably be expected to be in commercial operation at the date of testimony. (Tr. Vol. 5, p. 81) The Consumer Advocate did not propose any changes to the Company's original adjustment.

The Company subsequently revised its adjustment in order to reflect the actual in service dates of Units 3 and 4. As presented on Stimart Supplemental Exhibit 3, page 4a, the Company's revised adjustment to include Bad Creek in electric plant in service is $261,751,000. The Commission Staff also revised its recommendation to recognize the fact that Unit 4 began commercial operation on September 13, 1991. The Staff now proposes that $256,281,000 be included in electric plant in service for Bad Creek. (Tr. Vol. 5, p. 89) The ($5,470,000) difference between the Company's and Staff's revised adjustments is due to the Staff's exclusion of amounts it has not audited. (Tr. Vol. 5, p. 88) The Commission concludes that the revised adjustment proposed by the Company which reflects the total costs for all four units is appropriate. Based on the "Report of Accounting Department Administration Division" pages 3 and 4 (Hearing Exhibit 37), the Commission finds that there is no reason to conclude that the amounts proposed by the Company would be found to be unreasonable when audited.

Item 2. Accumulated Depreciation and Amortization

The differences between the parties' proposals are set forth below:

(000's)

	Company	Commission Staff	Consumer Advocate
Accumulated Depreciation and Amortization	$(1,357,590)	$(1,357,607)	$(1,357,860)
Difference		$(17)	$(270)

Analysis of Differences

Difference in Bad Creek Electric Plant In Service	$109	($270)
Depreciation Rate Change	$(126)	-0-
TOTAL DIFFERENCE	$(17)	$(270)

The Commission has previously determined that the adjustment to electric plant in service for Bad Creek proposed by the Company is appropriate. Therefore, the adjustments proposed by the Commission Staff and the Consumer Advocate regarding accumulated depreciation associated with their respective proposed levels of investment in Bad Creek are inappropriate.

Staff adjusted accumulated depreciation by the amount of the adjustment to depreciation expense for the Company's proposed depreciation rates. Although the Commission has previously found the Company's proposed depreciation rates to be appropriate for use in this proceeding, there is no evidence in the record supporting this adjustment to accumulated depreciation; therefore, the Commission rejects it. The appropriate level of accumulated depreciation and amortization to be reflected in rate base in this proceeding is ($1,357,590,000).

Item 3. Working Capital Investment

The differences among the parties concerning working capital have already been discussed in the Evidence and Conclusions for Finding of Fact No. 22 and will not be repeated here.

Item 4. Unclaimed Funds

Consumer Advocate witness Miller testified that unclaimed funds are a noninvestor source of funds which should be subtracted from rate base like other noninvestor sources of funds. Miller therefore deducted $214,000 from rate base. Witness Miller stated that he believes his recommendation is consistent with Commission precedent on this matter. (Tr. Vol. 5, p. 52) However, he failed to cite a particular case where this Commission had made such a ruling. The Commission concludes that the adjustment proposed by witness Miller is not appropriate for use in determining the level of original cost rate base for use in this proceeding.

Based upon the foregoing discussion, the following table provides the appropriate jurisdictional amounts for rate base as approved by the Commission:

(000's)

Electric Plant in Service	$3,390,362
Less:	
Accumulated Depreciation and Amortization	(1,357,590)
Net Electric Plant	2,032,772
Materials and Supplies	73,668
Plant Held for Future Use	4,402
Working Capital Investment	57,832
Less:	
Accumulated Deferred Taxes	(315,569)
Operating Reserves	(14,180)
Customer Deposits	(3,953)
Construction Work in Progress	-0-
Total Rate Base	$1,834,972

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The Commission has previously set forth the evidence supporting its findings of fact and conclusions regarding the fair rate of return which Duke Power Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenues and the rates of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. Such Schedules, illustrating the Company's gross revenue requirements incorporate the Findings of Fact and the Conclusions made herein by the Commission.

SCHEDULE I

DUKE POWER COMPANY
SOUTH CAROLINA RETAIL OPERATIONS
Docket No. 91-216-E
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 1990
(Thousands of Dollars)

Item	Before Increase	Approved Increase	After Increase
Electric Operating Revenue	$994,450	$68,384	$1,062,834
Electric Operating Expenses:			
Operation and Maintenance:			
Fuel Used in Electric Generation	197,625		197,625
Purchased Power and Nonfuel Net Interchange	141,680		141,680
Wages, Benefits, Materials, etc.	274,563		274,563
Depreciation and Amortization	121,499		121,499
General Taxes	48,755	278	49,033
Interest on Customer Deposits	468		468
Income Taxes	57,562	25,403	82,965
Amortization of ITC	(4,395)		(4,395)
Total Electric Operating Expenses	837,757	25,681	863,438
Operating Income	$156,693	$42,703	$199,396

SCHEDULE II

DUKE POWER COMPANY
SOUTH CAROLINA RETAIL OPERATIONS
Docket No. 91-216-E
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1990
(Thousands of Dollars)

Item	Amount
Electric Plant In Service	$3,390,362
Less: Accumulated Depreciation and Amortization	(1,357,590)
Net Electric Plant	2,032,772
Add: Materials and Supplies	73,668
Working Capital Investment	57,832
Plant Held for Future Use	4,402
Less: Accumulated Deferred Taxes	(315,569)
Operating Reserves	(14,180)
Customer Deposits	(3,953)
Construction Work in Progress	0
TOTAL RATE BASE	$1,834,972
RATE OF RETURN	
Present	8.54%
Approved	10.87%

SCHEDULE III

DUKE POWER COMPANY
SOUTH CAROLINA RETAIL OPERATIONS
Docket No. 91-126-E
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1990
(Thousands of Dollars)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-Term Debt	40.50%	743,164	8.78%	65,250
Preferred Stock	9.68%	177,625	7.74%	13,748
Common Equity	49.82%	914,183	8.50%	77,696
Total	100.00%	$1,834,972		$156,693
	Approved Rates - Original Cost Rate Base			
Long-Term Debt	40.50%	743,164	8.78%	65,250
Preferred Stock	9.68%	177,625	7.74%	13,748
Common Equity	49.82%	914,183	13.17%	120,399
Total	100.00%	$1,834,972		$199,396

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Denton, Staff witness Watts, Consumer Advocate witness Lanzalotta and SCEUC witness Phillips. Mr. Denton described the changes Duke proposes for the Company's various rate schedules. The Company proposes to consolidate its three non-time-of-use residential rates into two new rate schedules: (1) RS, residential service; and (2) RE, residential service, electric water heating and space conditioning. Both rates include conservation discounts. These proposed rate schedules eliminate present rate Schedules R, RC, and RA and reassign customers to new Schedules RS and RE. Schedule RS consists of four categories. Category 1 applies to any residential

customer. Category 2 applies to residential customers with qualifying electric water heaters. Category 3 applies to residential customers meeting certain thermal conditioning requirements. Category 4 applies to residential customers meeting both the requirements for Categories 2 and 3. Schedule RE applies to residential customers where all energy required for water heating, cooking, clothes drying, and space conditioning is supplied electrically. This schedule consists of two categories. Category 1 applies to customers meeting specific requirements for electric water heaters and electric space conditioning. Category 2 applies to customers meeting the same specific thermal conditioning requirements as those required by Schedule RS, Category 3 and 4. Mr. Denton explained that the new schedules place customers in more homogeneous groups based on the equipment installed in their homes and permits targeted price signals to these homogenous groups.

As a result of the proposed residential rate design charges, some customers on each rate schedule will receive bill increases greater than the percentage increase for the residential class. Duke proposes to create Schedule RB for these customers who would otherwise receive an increase of 5% or more above the average residential class increase, and limit the magnitude of the increase to Schedule RB customers to 5% above the average residential increase. Duke also plans to encourage customers who will receive an increase greater than the increase for the class to move to time-of-use Schedule RT, which may minimize the impact of the proposed increase.

Mr. Denton also explained the proposed modifications to general service and industrial rate schedules. Duke proposes to modify Schedules G, GA, and I to eliminate the confusion caused by GA being available to both general service and industrial customers. Under the current rate design, it is sometimes difficult for customers to determine the appropriate rate for their usage. Duke proposes that industrial customers be served on Schedule I, and that general

service customers be served on Schedules G and GA. The billing demand provision of Schedule GA currently applied to industrial customers would be maintained for Schedule GA customers moving to Schedule I. For general service customers, Duke proposes to retain Schedules G and GA with certain modifications. Under each rate, the price during April through November will be the same. The months of December through March will have lower energy charges for Schedule GA. These changes will reduce customer confusion in the general service class over which rate is more advantageous. Bills under Schedule GA will always be equal to or lower than bills under Schedule G.

The Company proposes to reduce the Schedule OPT summer on-peak hours from ten to eight, with the on-peak period beginning at 1:00 p.m. and ending at 9:00 p.m. The reduction is proposed to make it easier for customers to shift production off-peak by allowing them to operate two eight-hour shifts during the off-peak period. SCEUC witness Phillips agrees with the proposed change, in on-peak hours. (Tr. Vol. 4, p. 125) No other party expressed opposition to the modified hours. Therefore, the Commission concludes that the modified summer on-peak hours on Schedule OPT proposed by the Company should be adopted.

The Company proposes to increase closed rate schedules GB, GT, and IT 2% more than the overall general increase to encourage customers to move from these rates to open rate schedules. This proposal was opposed by SCEUC witness Phillips, who proposes that Schedule OPT be revised by lowering demand and energy charges to make it more attractive to Schedule I and IT customers, rather than simply increasing the rate to move customers. Mr. Phillips also proposes that the increase for Schedule GB, GT, IT, and I be limited to the average of the industrial class increase. (Tr. Vol. 4, pp. 126-127)

Mr. Denton also described the proposed changes to lighting schedules. Duke currently has four lighting schedules, Schedules T, T2, T2X, and FL. Schedule T, Street Lighting Service, is available to governments for public

lighting. Duke proposes to change the name to Schedule PL, Street and Public Lighting Service. Schedule T2, Outdoor Lighting Service, would be designated Schedule OL. The designation of Schedule FL, Floodlighting Service, would not change.

Duke is proposing additional pricing levels for Schedules OL and FL to cause new customers to pay the higher cost of installing lights when a pole installation is requested by the customer. The proposed rates include pricing for a new luminaire on an existing pole, for the installation of a new pole, and a price for a new pole installation and underground service. Existing installations would be served on the luminaire-only rate. Schedule T2X, Subdivision Entrance Lighting Service, is currently available for lighting entrances to subdivisions and other public areas. Duke is proposing to cancel Schedule T2X and offer new mercury vapor and high pressure sodium vapor post-top luminaires on Schedule OL.

Finally, Duke proposes that a pilot program named "Limited Demand Charge Days" (LDCD) be approved. The pilot program will be used to determine to what extent industrial customers will change their consumption characteristics during times of adequate supply by limiting demand charges during these periods. Customers would be able to increase their consumption during these periods without incurring an increased billing demand.

Staff witness Watts testified that the Electric Department reviewed Duke's rates, tariffs and service regulations, and verified the requested increase by rate schedule. Based on the Staff's review and audit, it concurs with the Company's proposed rate design changes.

Consumer Advocate witness Lanzalotta testified that the increase in Schedule RS should be no larger than the increase for the residential class, and that the proposed tailblock rate in Schedule RE should not be less than the tailblock rate in Schedule RS. This proposal would eliminate the discount for

efficient air conditioning and high levels of insulation. Mr. Lanzalotta testified that Duke's residential rate design improperly encourages the use of electric space heating, water heating, and air conditioning. Mr. Lanzalotta is correct when he asserts that Duke's rate design will encourage electric heating and water heating. Duke has encouraged efficient heat pumps on its system to create off-peak winter sales. Such sales improve Duke's load factor, which enables fixed costs to be spread over a large number of kilowatt/hours. This benefits all customers by lowering the unit cost of electricity. (Tr. Vol. 4, pp. 106-107; 110-111) Mr. Lanzalotta's recommendations are inconsistent with Duke's efforts that are clearly beneficial to Duke's customers. Mr. Lanzalotta's criticisms of Duke's discounts for efficient air conditioning and high levels of insulation is also misplaced. Duke is a summer peaking utility, with a significant air conditioning load. The discount in Schedule RE which Mr. Lanzalotta criticizes will encourage efficient air conditioning and conservation. These are appropriate goals of rate design which the Commission has adopted in prior cases and will continue.

The parties have made other proposed revisions to the rate schedules proposed by Duke which are not specifically addressed in this Order. The Commission has carefully considered the testimony and exhibits of each party. The remaining proposals, while not specifically addressed, must be rejected by the Commission. Duke's proposed rate design, rate schedules, miscellaneous charges, and terms and conditions should be approved, except as specifically modified in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Denton, Staff witness Watts, and SCEUC witness Phillips. In his direct testimony, Mr. Denton explained that different percentage increases were applied to customer classes to help move the

Residential and Industrial classes toward the "band of reasonableness", a band or range of plus or minus 10% of the average retail rate of return. Mr. Denton testified that the industrial class is experiencing a significantly higher rate of return than average, and the residential class is experiencing a significantly lower return than average. Duke proposes to allocate the increase in revenue to trend toward equal rates of return.

SCEUC witness Phillips testified that Duke's proposed allocation of the revenue increase does not adequately move class rates of return toward equality. Under Mr. Phillips proposal, the remaining difference would be reduced in future rate cases. Mr. Phillips proposed as an alternative that the Commission utilize the difference between Duke's requested increase and the actual increase granted to reduce or eliminate overpayments made by the industrial class. (Tr. Vol. 4, pp. 121-122)

Staff witness Watts recommended adoption of the Company's Cost of Service Studies with certain modifications. (Tr. Vol. 5, p. 238)

The Commission concludes for purposes of this proceeding that the revenue increase should be allocated to the extent practical to bring the Industrial class return to the band of reasonableness.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this Finding of Fact is contained in the testimony and exhibits of Company witness Denton and SCEUC witness Phillips. Rider IS is the interruptible service rider under which general service and industrial customers receive a credit from Duke to curtail their load at Duke's request. Duke proposes to increase the cost to the customer in each situation where the customer does not interrupt his load at Duke's request. The current cost to the customer for failing to interrupt is $1.58/KW. Under the proposed revised Rider IS, each time the customer fails to interrupt, approximately one third of the credits paid to the customer during the year are to be repaid to Duke.

If a customer fails to interrupt three times during the year, all credits paid during the prior twelve months would be repaid to Duke and the customer would be removed from Rider IS. Mr. Denton testified that this change will send a much stronger price signal to customers so that when Duke requests an interruption of load, the Company can expect customers to reduce their load to the level agreed to in their Rider IS contracts. Duke also proposes to make the exposure period consistent with Schedule OPT by reducing the exposure hours during the summer to equal the proposed summer on-peak hours.

No party objected to the proposed change in penalty provision. However, SCEUC witness Phillips proposes that the credit rate be increased from the present $3.50/KW to a range of $6.25/KW to $7.50/KW per month. (Tr. Vol. 4, pp. 129-130). Duke is attracting a sufficient amount of interruptible load at the present credit and has requested an increase in the system cap to 1100 megawatts.

The Commission agrees with the Company that an increase in the Rider IS credit is not necessary to attract a sufficient level of interruptible load.

IT IS, THEREFORE, ORDERED AS FOLLOWS:

1. That Duke Power Company be, and is hereby, allowed to adjust its electric rates and charges so as to produce, based upon the adjusted test year level of operations, an increase in annual gross revenues of $68,384,000 from its South Carolina retail operations. This increase shall be effective for service rendered on and after the date of this Order.

2. That within _____ working days after the date of this Order, the Company shall file with the Commission _____ copies of computations showing the overall South Carolina retail rate of return which will be produced by the revenues approved by this Order. Such computations shall be based on the cost allocation methodology approved herein.

3. That the Company shall give appropriate notice of the rate increase approved herein by mailing a notice to each of its South Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described in Decretal Paragraph No. 2 above.

4. That the following holidays shall be classified as off-peak periods for Schedules RT and RTE: New Year's Day, Good Friday, Memorial Day, July 4, Labor Day, Thanksgiving (Thursday and Friday), and Christmas Day.

5. That the Company shall provide a separate statement to residential time-of-use customers showing on-peak and off-peak kwh usage and savings over non-time-of-use rates.

6. That the Company shall offer a time-of-use comparative billing program to its residential customers, and that such program may be limited to 1,000 volunteers on the system at a time.

7. That the Company's pilot program, "Limited Demand Charge Days", is approved as filed.

8. That the Stipulation dated September 23, 1991, between the Commission Staff, the Consumer Advocate, and Duke relating to Demand-Side Management cost deferral, attached to this Order as Appendix 1, is approved by the Commission and is hereby incorporated as a part of this Order.

9. That the request for deferral accounting as described in the Stipulation is allowed. Duke shall include as a deferred debit in Account No. 186, Miscellaneous Deferred Debits, the DSM program costs up to $6.475 million (South Carolina Retail) as described in the Stipulation which have not been reflected in cost of service in this docket. A return on the deferred balance shall be computed monthly and added to the balance. The rate of return will equal the net of tax rate of return approved by the Commission in this proceeding or in subsequent rate cases.

10. That Duke will include as a deferred credit in Account No. 253, Other Deferred Credits, all collections it receives from CP&L pursuant to Schedule J and will accrue carrying costs on such amounts net of tax at the then applicable allowed rate of return.

11. That any motions, contentions or proposed adjustments filed in this proceeding and not previously ruled upon, are hereby denied.

12. That this Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

_____
Chairman

ATTEST:

_____
Executive Director

(SEAL)

APPENDIX 1

STATE OF SOUTH CAROLINA

BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION

DOCKET NO. 91-216-E

IN THE MATTER OF:	)	
Application by Duke Power Company for Authority to Adjust and Increase Its Electric Rates and Charges	)	STIPULATION

The Public Service Commission Staff (Staff), Duke Power Company (Duke), and Steven W. Hamm, Consumer Advocate for the State of South Carolina (Consumer Advocate) enter this Stipulation for approval by the South Carolina Public Service Commission (Commission) in the above-captioned case as follows:

1. On or about May 17, 1991, Duke Power Company (Duke or the Company) filed an Application requesting that the Commission approve an increase in the Company's South Carolina retail electric rates and charges.

2. The Commission has assigned Docket No. 91-216-E to this matter and has scheduled a public hearing to begin in the Commission's offices Monday, September 23, 1991.

3. As part of its Application in Docket No. 91-216-E, Duke is proposing approximately $6.475 million for additional expenditures in what it refers to as Demand-Side Management (DSM) programs, including ongoing programs, pilot programs, end-use metering and program evaluations, and funding for the Industrial Electrotechnology Laboratory (IEL). See Denton Prefiled Testimony at 15. Duke is also proposing to recover approximately $5.6 million in 1990 test year costs for these DSM programs already booked.

4. Recently in Docket No. 87-223-E, the parties to this Stipulation, as well as other parties, have agreed to comprehensive integrated resource planning

procedures for use by utilities and other interested parties subject to the Commission's jurisdiction, including the requirement that utilities are to submit by April 30, 1992 Integrated Resource Plans (IRPs) in accordance with the procedures agreed to and approved by the Commission therein.

5. In consideration of these recent developments, the parties agree that the test year (1990) expenditures including advertising expense in South Carolina already incurred and booked may be recovered as proposed in Docket No. 91-216-E. DSM costs for the programs listed on page 15 of Mr. Denton's prefiled testimony actually incurred above this 1990 level up to a total of $6.475 million may be booked into a deferred account for possible inclusion in the cost of service and rates in a subsequent rate case or IRP docket. Advertising expenditures for these programs that are at a reasonable level and type in light of the actual net program benefits may be deferred as well, provided that they are designed, as well, to achieve the goals of the respective DSM program. At the time the Company seeks to expend funds higher than the cumulative total of $6.475 million for new or existing programs or at the time the Company seeks approval of new or modified DSM programs, the Company will enumerate the nature and level of the costs contemplated to be deferred by program as a part of obtaining Commission approval. The Company will credit the deferred account for found revenues to the extent lost revenues resulting from lost kwh sales due to DSM conservation programs are included in the deferred account and for appropriate DSM costs recovered from ratepayers. The parties will have an opportunity for discussion and discovery as provided in the IRP rules prior to the Commission decision. The parties shall in good faith cooperate toward expeditious consideration of any new programs proposed and any additional amounts deferred between formal IRP and STAP filings.

A return on the deferred balance will be computed monthly and added to the balance. Interest will be compounded annually. The rate of return will equal the net of tax rate of return approved by the Commission in Docket No. 91-216-E or subsequent rate cases. If it is determined that the expenditures were prudent and for used and useful DSM programs, the balance in the deferred account will be reflected in Duke's next rate case or appropriate IRP docket by amortizing the then existing balance over a period of five years, except the Commission may order a different period if the amount in the deferred account would have a significant impact on rates.

6. In consideration of Commission approval of this Stipulation prior to the close of the evidentiary portion of the instant rate case docket, they agree: (a) to entry of this Stipulation into evidence; (b) to allow all relevant prefiled testimony, as well as any rebuttal and surrebuttal testimony, to be entered into the record as if given orally; (c) not to cross examine witnesses on these expenditures or IRP; (d) not to have this Stipulation considered as a waiver of any objections to Duke's approach to IRP or to the prudence of any of its DSM programs or expenditures to be deferred, and (e) that the cost recovery methodology set forth in this Stipulation does not represent the cost recovery methodology Duke will propose in the IRP proceeding and that this cost recovery process may apply only until the Commission establishes an appropriate cost recovery plan for Duke.

7. The parties agree, however, that the Commission's approval of this Stipulation does not bind these parties or others not party to it to challenge the reasonableness of any of the programs or deferred expenditures above the level in rates in the future when their approval or cost recovery is requested.

8. The parties further agree that the Commission may consider based on the record for inclusion in rates in some manner over and above 1990 test year

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costs, in cost of service as a separate component not subject to this deferral method, in Docket No. 91-216-E, the additional DSM costs it finds are actual and prudently incurred or prudently committed costs in 1991 attributable to the Duke Interruptible Service Program, Stand-by Generator Program, Water Heater and Air Conditioner Load Control Programs and associated advertising costs as described in Paragraph 5, above, for these programs. The additional costs subject to possible inclusion in rates are identified on Appendix 1.

This 23rd day of September, 1991.

Respectfully submitted,

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APPENDIX 1

DUKE POWER COMPANY
SCPSC DOCKET NO. 91-216-E

1991 Demand Side Program Costs
Which May be Considered for
Inclusion in Rates Approved in
SCPSC Docket No. 91-216-E

Interruptible Service Credits	$ 3,668,342
Standby Generator Payments	-0-
Water Heater and Air Conditioner Load Control Costs	242,472
Advertising Costs	-0-
	$ 3,910,814

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BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2009-226-E

In the Matter of:	)	
	)	
Application of Duke Energy Carolinas,	)	DIRECT TESTIMONY OF
LLC for Authority to Adjust and Increase	)	DHIAA M. JAMIL FOR
Its Electric Rates and Charges	)	DUKE ENERGY CAROLINAS, LLC
	)	
	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, ADDRESS, AND POSITION.

A. My name is Dhiaa M. Jamil. My business address is 526 South Church Street, Charlotte, North Carolina. I am Group Executive and Chief Generation Officer for Duke Energy Corporation ("Duke Energy") and Chief Nuclear Officer ("CNO") for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY?

A. As Group Executive and Chief Generation Officer, I am responsible for the safe, reliable, and efficient operation of the Company's nuclear, fossil, and hydro fleets.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in electrical engineering. I am a professional engineer in North Carolina and South Carolina and have completed the Institute of Nuclear Power Operations' ("INPO") senior nuclear plant management course and received my Duke Energy technical nuclear certification. I served as a senior member of the Institute of Electrical & Electronics Engineers ("IEEE") and recently completed a three-year assignment as a member of the Council of the National Academy for Nuclear Training. I was also a member of Dominion Energy Management Safety Review Advisory Committee, the Tennessee Valley Authority Nuclear Safety Review Board, and currently serve on the INPO Executive Advisory Group and the Charlotte Research Institute board of directors.

I am currently the chairman of the Energy Production and Infrastructure Center ("EPIC") Advisory Board for the University of North Carolina at Charlotte. I

began my career at Duke Energy Carolinas in 1981 as a design engineer in the design engineering department. After a series of promotions, I was named Oconee Nuclear Station Electrical Systems Engineering Supervisor in 1989; Electrical Engineering Manager in 1994; Maintenance Superintendent, McGuire Nuclear Station, in 1997; Station Manager of McGuire in September 1999; and Vice President of McGuire Nuclear Site in September 2002. I was named Vice President of Catawba Nuclear Station in July 2003, with responsibility for all aspects of the safe and efficient operation of the nuclear site. In December 2006, I was named Senior Vice President of Nuclear Support, where I was responsible for plant support, major projects and fuel management for the nuclear fleet. I was also responsible for regulatory support, nuclear oversight and safety analysis functions. I was named Group Executive and Chief Nuclear Officer in January 2008. Earlier this month I was named to my current role as Group Executive and Chief Generation Officer for Duke Energy and continue in the role of Chief Nuclear Officer for Duke Energy Carolinas.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) provide an overview of the nuclear and fossil-hydro generation assets; (2) discuss the purchase of a portion of Saluda River Electric Cooperative, Inc.'s ("Saluda River") interest in the Catawba Nuclear Station and other nuclear and fossil-hydro capital additions since the 1991 rate case; (3) discuss the operational performance of Duke Energy Carolinas' nuclear generation and fossil-hydro fleet during the January 2008 through December 2008 test period;

and (4) discuss key drivers impacting O&M costs for nuclear and fossil-hydro operations.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' NUCLEAR GENERATION PORTFOLIO.

A. Duke Energy Carolinas' nuclear generation portfolio consists of approximately 5,200 megawatts ("MWs") of generating capacity, made up as follows:

Oconee Nuclear Station - 2,538 MWs

McGuire Nuclear Station - 2,200 MWs

Catawba Nuclear Station - 435 MWs (Duke Energy Carolinas' 19.2% ownership of the Catawba Nuclear Plant)

Q. MR. JAMIL, PLEASE PROVIDE A GENERAL DESCRIPTION OF DUKE ENERGY CAROLINAS' NUCLEAR GENERATION ASSETS.

A. Duke Energy Carolinas' nuclear fleet consists of three generating stations. Oconee Nuclear Station, located in Oconee County, South Carolina, began commercial operation in 1973 and was the first nuclear station designed, built and operated by Duke Energy Carolinas. It has the distinction of being the second nuclear station in the country to have its license renewed, originally issued for 40 years, by the U.S. Nuclear Regulatory Commission ("NRC") for an additional 20 years.

McGuire Nuclear Station, located in Mecklenburg County, North Carolina, began commercial operation in 1981. Duke Energy Carolinas jointly owns the Catawba Nuclear Station, located on Lake Wylie in York County, South Carolina, with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation ("NCEMC"), and Piedmont Municipal Power Agency. Catawba began commercial operation in 1985. In 2003, the NRC renewed the

licenses for McGuire and Catawba for an additional 20 years each. On September 30, 2008, the Company and NCEMC closed on the purchase of Saluda River's ownership interest in Unit 1 of Catawba Nuclear Station. Following the close of the purchase, Duke Energy Carolinas' ownership interest in the Catawba station increased from 12.5% to 19.2%.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' FOSSIL-HYDRO GENERATION PORTFOLIO.

A. Duke Energy Carolinas' fossil-hydro generation portfolio consists of approximately 14,000 megawatts ("MW") of generating capacity, made up as follows:

Coal-fired generation -	7,672 MWs
Hydroelectric -	3,218 MWs
Combustion Turbines -	3,142 MWs

(Combustion turbines can operate on natural gas or fuel oil)

This portfolio includes a diverse mix of units that, along with Duke Energy Carolinas' nuclear capacity, allow the Company to meet our customers' dynamic load requirements in a logical and cost-effective manner. As customer load has grown, a greater percentage of load has been served from the coal-fired units. In 2008, the nuclear units provided approximately 47% of Duke Energy Carolinas' total generation, the coal units provided 53%, and the hydroelectric system and the combustion turbines were available to provide critical peaking power.

II. INCREASED OWNERSHIP INTEREST IN CATAWBA AND OTHER NUCLEAR AND FOSSIL-HYDRO CAPITAL PROJECTS

A. CATAWBA NUCLEAR STATION

Q. PLEASE DESCRIBE THE TRANSACTION THAT LED TO DUKE ENERGY CAROLINAS' INCREASED OWNERSHIP INTEREST IN THE CATAWBA NUCLEAR STATION.

A. The Commission approved the amendment to the Certificate of Environmental Compatibility and Public Convenience and Necessity (the "Certificate") for the Catawba station to reflect the transfer of Saluda River's interest to Duke Energy Carolinas and NCEMC by Order No. 2008-468 in Docket No. 2008-117-E. On September 30, 2008, Duke Energy Carolinas completed the purchase of a portion of Saluda River's approximately seven percent ownership interest ("Saluda River Interest") in the Catawba Nuclear Station, thereby increasing its ownership interest in the Station from 12.5% to 19.2% (282 MW to 435 MW). Under the terms of the agreement, Duke Energy Carolinas paid approximately $150 million for the additional ownership interest in Catawba. The assets purchased included decommissioning funds of approximately $41.5 million that Saluda River had accumulated for its share of decommissioning the plant. The funds were transferred to the external trustee responsible for managing Duke Energy Carolinas' decommissioning fund. Following the closing of the transaction, the Company owns approximately 19.2% of the Catawba Nuclear Station.

Q. HOW DID THE COMPANY DETERMINE THAT THIS WAS THE BEST RESOURCE OPTION FOR ITS CUSTOMERS?

A. As reflected in the Joint Application of Duke Energy Carolinas, LLC; N.C. Electric Membership Corporation; and Saluda River Electric Cooperative, Inc. to Amend the Certificate of Environmental Compatibility and Public Convenience and Necessity for Catawba Nuclear Station filed in Docket No. 2008-117-E, Duke Energy Carolinas evaluated the purchase of 71.96% of the Saluda River Interest in Catawba Nuclear Station as part of its 2006 and 2007 Integrated Resource Planning ("IRP") process and determined that the addition of Saluda River's share of Catawba Nuclear Station was a least-cost addition to the Company's generation portfolio and would benefit its customers. I understand that Duke Energy Carolinas' 2006 IRP filed with the Commission in Docket No. 2005-356-E showed a need for the capacity in the timeframe of the acquisition, and the purchase of the Saluda River Interest in Catawba and the gas-fired generation were the only viable options available. To determine the maximum price the Company should pay for the Saluda River Interest in Catawba the Company performed a life-cycle analysis comparing it to an equal amount of capacity from a combined-cycle gas-fired generation plant. The purchase price for the Saluda River Interest in Catawba did not exceed the maximum price determined in the life-cycle analysis.

B. NUCLEAR FLEET

Q. WHAT MAJOR CAPITAL PROJECTS HAS THE COMPANY UNDERTAKEN RELATIVE TO ITS NUCLEAR FLEET SINCE THE 1991 RATE CASE?

A. Since 1991, Duke Energy Carolinas has spent more than $1.5 billion in capital projects to improve the performance of its nuclear facilities and to address refurbishments in order to ensure reliable extended life operations due to license renewals granted by the NRC for Oconee, McGuire, and Catawba. Of the $1.5 billion spent, the Company closed nuclear capital projects that cost more than $330 million in 2007 and 2008 alone. These recent projects include work necessary to comply with a NRC regulatory requirement to modify the containment sump at McGuire and Catawba that Ron Jones discussed in his testimony in Docket Nos. 2008-3-E and 2007-3-E; Alloy 600 mitigation efforts and groundwater monitoring; as well as mitigation of service water system piping degradation at Catawba due to raw water corrosion and biological effects on the carbon steel piping.

Q. IN YOUR OPINION ARE THESE NEW NUCLEAR GENERATION ADDITIONS USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DUKE ENERGY CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN SOUTH CAROLINA?

A. Yes they are. The acquisition of a larger percentage ownership of Catawba provides the Company with additional base load capacity from a low cost generation asset that has been successfully operating for over 20 years. As I discussed above, the Company determined this acquisition was the least cost resource to meet increases in customer demand. Additionally, customers already are benefiting from reduced fuel

costs associated with additional nuclear capacity. As a result of the Company's successful efforts to renew the licenses of its nuclear fleet, each for an additional 20 years, customers will continue to benefit from the generation provided by this reliable, cost-effective, and greenhouse gas emission-free base load source of electricity into the early-2040s. Our investments in refurbishment and enhanced performance of our existing nuclear fleet allow for the continued reliable and efficient operation of these assets that is reflected in the nuclear capacity factors I discuss below.

Q. WHAT TYPES OF PROJECTS ARE IN THE CAPITAL BUDGET FOR NUCLEAR OPERATIONS FOR THE NEXT THREE YEARS?

A. Over the next three years, the Company's plans include approximately $1 billion in capital spending. This budget includes similar types of projects to those in 2007 and 2008; however, projects related to regulatory commitments to the NRC for the continued operation of the Oconee Nuclear Station are driving the budget higher than in prior years. For the next several years, we will continue to pursue numerous projects necessary to support the extended life of our existing units, increase their reliability and upgrade technology. We also are performing a study to evaluate the potential to develop additional nuclear capacity through increasing the maximum power level at which our existing facilities may operate, called a power uprate. Major capital projects for the next three years include work related to the goal of continued safe, reliable operations, refurbishment of aging equipment, replacement or upgrades of obsolete equipment, and upgrades and additions to plant systems based on changing regulations and standards. We plan

for replacement of aged piping and components, based on systematic monitoring that has been performed.

Some additional examples include upgrading obsolete and aging analog controls systems to more reliable and accurate digital controls systems, and upgrades and enhancements to plant systems to meet changing regulatory requirements related to security, emergency response, and materials upgrades. We are planning upgrades to plant structures and systems to address regulatory guidance concerning nuclear safety associated with natural events such as tornados. Additionally, the Company plans for capital expenditures associated with development work to preserve the option to build the Lee Nuclear Station. A description of such development work can be found in my direct testimony before this Commission in Docket No. 2007-440-E.

In addition to the projects included in the capital budget, the Company is also (1) reengineering certain of the Oconee projects necessary to meet NRC commitments that I noted above and (2) considering the appropriate timeframe in which to implement uprates if the study results are positive. These considerations may necessitate capital investment over and above the current capital budget.

C. FOSSIL-HYDRO FLEET

Q. WHAT FOSSIL-HYDRO PLANTS HAVE BEEN ADDED SINCE THE 1991 RATE CASE?

A. In 1995, we added 1,267 MWs of combustion turbines to the Duke Energy Carolinas system at the Lincoln site in Stanley, North Carolina. In 2002 and 2003, we added 595 MWs of combustion turbines to the system at the Mill Creek site in Blacksburg, South Carolina. In November 2006, we acquired 825 MWs of combustion turbines

from Rockingham Power, LLC, a subsidiary of Dynegy, Inc., at the Rockingham site in Rockingham County, North Carolina. In January 2007, we replaced the combustion turbines at the Lee Steam Station in Anderson County, South Carolina with new combustion turbine facilities constituting 84 MWs.

Q. FOCUSING ON MORE RECENT CAPITAL PROJECTS, WHAT FOSSIL-HYDRO RATE BASE ADDITIONS HAVE BEEN ADDED SINCE 2007?

A. The Company's fossil-hydro rate base additions during the period 2007 through 2009 fall into three categories: environmental additions, reliability improvements, and hydro relicensing projects. The most significant capital addition to the Company's fossil-hydro fleet in this period is the flue gas desulfurization equipment ("FGD" or "scrubber") at the Allen Steam Station. These two scrubbers serve all five units at the Allen plant and began commercial operation between February and May 2009. This equipment has the capacity to reduce sulfur dioxide ("SO_2") emissions by greater than 95%. The direct capital cost associated with the Allen scrubbers is projected to be $502.8 million.

Additionally, in December 2008 we added selective catalytic reduction ("SCR") equipment at Marshall Unit 3 in support of various nitrogen oxide ("NO_X") control requirements, most notably the 8-hour ozone standard in the Charlotte region. The direct capital cost associated with the Marshall Unit 3 SCR equipment through June 30, 2009 is $105.0 million, and we expect to spend an additional $1.5 million on project close-out activities. This SCR equipment has the ability to reduce the NO_X emission rate for the unit by 80%. Other environmental projects such as coal combustion by-product ("CCP") landfill and dry storage, SCR catalyst

additions, and mercury monitoring requirements involved an additional $84.3 million in capital spending.

Since 2007, we have completed numerous projects focusing on the improved reliability of the Company's fossil-hydro fleet. Turbine and generator ("T/G") equipment reliability has been a major focus area, and $71.3 million has been spent on projects such as generator stator and rotor rewinds, turbine steam path upgrades, turbine valve replacements, turbine rotor replacements, and other supporting T/G equipment. The coal fleet boilers continue to be a major focus of reliability programs as well; $72.7 million has been spent on boiler tube replacements and supporting boiler equipment projects to minimize forced outage events. This focus on unit availability and reliability also extends out to the remaining balance of plant equipment where an additional $78.8 million has been spent on projects related to valves, coal mills, coal handling equipment, controls, electrical equipment, motors and other equipment. In light of severe drought and low stream flow conditions experienced in Duke Energy Carolinas' service territory during 2007 and 2008, the Company spent $21.2 million implementing capital projects to increase its ability to operate its generation units at reduced reservoir levels and stream flows.

In addition to these projects I have described, Duke Energy Carolinas has invested $56.7 million on projects required for hydro relicensing and other smaller programs related to its existing fossil-hydro fleet.

Q. IN YOUR OPINION ARE THESE POST-1991 GENERATION ADDITIONS USED AND USEFUL IN PROVIDING SERVICE TO DUKE ENERGY CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN SOUTH CAROLINA?

A. Yes, they are. The combustion turbine facilities provide critical peaking resources for use in meeting our customers' energy needs during periods of highest demand. In addition, the Rockingham CT facility is available to provide VAR support when needed in our Northern Region and the Lee CTs provide backup power to the Oconee Nuclear Station.

The environmental projects are necessary for compliance with local, State, and Federal environmental regulations. The $502.8 million cost of the Allen scrubbers is necessary to comply with the North Carolina Clean Smokestack Act and with Phase 1 of the Federal Clean Air Interstate Rule ("CAIR"). Phase 1 of CAIR begins in 2010 for SO_2 unless and until the Environmental Protection Agency ("EPA") promulgates a new rule.

The additional capital investments I discussed above have enabled the Company to continue to provide reliable generation service to our customers at reasonable costs.

Q. WHAT IS THE ANTICIPATED CAPITAL BUDGET FOR FOSSIL-HYDRO OPERATIONS OVER THE NEXT THREE-YEAR PERIOD?

A. The Company has delayed some capital spending in light of the credit crunch; however, in order to meet environmental compliance requirements and to continue to provide reliable service to customers, Duke Energy Carolinas plans to invest approximately $1 billion in its fossil-hydro plant during the period 2009-2011.

III. OPERATIONAL PERFORMANCE

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN THE OPERATION OF ITS GENERATION ASSETS?

A. The primary objective of Duke Energy Carolinas' generation departments is to safely provide reliable and cost effective electricity to the Company's Carolinas customers. The Company achieves this objective through its focus in a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards, in accordance with detailed procedures, guidelines, and a standard operating model. The Company maintains station equipment and systems reliably, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Equipment inspections, maintenance outages and station refuelings are conducted through the execution of well-planned, quality work activities, which effectively ready the plant for operation until the next planned outage. Like safety, regulatory compliance is a "first principle," and we work very hard to achieve compliance with all applicable NRC and environmental regulations.

A. NUCLEAR GENERATION TEST YEAR PERFORMANCE

Q. PLEASE DISCUSS THE COMPANY'S NUCLEAR GENERATING SYSTEM PERFORMANCE DURING THE PERIOD JANUARY 2008 THROUGH DECEMBER 2008.

A. Overall, our nuclear plants operated extremely well, supplying almost half of the power used by our customers during 2008. The Company's seven nuclear units operated at a system average capacity factor of 91.50% during the test period, which was the fourth highest capacity factor for a five refueling outage year. In addition,

Oconee Unit 3 and Catawba Unit 2 set capacity factor records of 101.94% and 102.88%, respectively. McGuire Unit 2 ended a 475.98 day breaker-to-breaker run when it began its refueling outage in March 2008. According to statistical data provided by the Electric Power Research Institute, Catawba Nuclear Station was the third most thermally efficient nuclear power plant in the United States, in 2008. In addition, the Nuclear Energy Institute ("NEI") recognized two Duke Energy programs with its Top Industry Practice ("TIP") Awards. In the community relations category, the Company was honored for 40 years of a formal nuclear community relations program. In the material and services category, Catawba's high-density polyethylene ("HDPE") piping project was honored. Catawba participated as the pilot plant for this project, which used this piping for the complete replacement of a metallic service water system. Completion of this project has resulted in substantially improved performance at a lower capital and maintenance cost because HDPE is not subject to corrosion or fouling.

The system average nuclear capacity factor has been above 90% for nine consecutive years. As I testified above, the achieved test year system nuclear capacity factor was 91.50%. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of the Company's nuclear system. The Company's nuclear performance has improved dramatically over the course of the years of operating its nuclear fleet. In particular, improved reliability and lower forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet as discussed above.

In an effort to continue this trend, the nuclear organization is placing additional focus on pre-outage planning and milestone adherence through a fleet-wide approach to outage planning. An example of the emphasis put on this effort in 2008 is the Company's creation of a scheduled Outage Improvement Team, which is assigned the task of maximizing scheduled outage predictability without compromising safety and reliability.

B. FOSSIL-HYDRO GENERATION TEST YEAR PERFORMANCE

Q. PLEASE DISCUSS THE PERFORMANCE OF DUKE ENERGY CAROLINAS' FOSSIL GENERATING SYSTEM DURING THE TEST PERIOD.

A. Duke Energy Carolinas' fossil generating system operated efficiently and reliably during the test period. Two key measures are used to evaluate the operational performance of generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power if needed. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity.

Duke Energy Carolinas' seven base load coal units achieved results of 84.5% equivalent availability factor and 76.6% capacity factor over the test period. During the peak summer season within this test period, these base load units achieved excellent results of 91.7% equivalent availability factor and 83.1% capacity factor. The Company's thirteen intermediate coal units achieved results of 84.2% equivalent availability factor and 55.8% capacity factor over the test period, and

performed similarly during the summer peak months at 86.0% equivalent availability and 62.3% capacity. Duke Energy Carolinas' ten peaking coal units achieved results of 88.7% equivalent availability factor and 32.7% capacity factor for the test period, and performed similarly during the summer peak months at 84.7% equivalent availability and 36.2% capacity.

The Company's combustion turbines were available for use as needed in this time period, with a 95.9% starting reliability result for the large combustion turbines at the Lincoln, Mill Creek, and Rockingham plants.

These results are indicative of solid performance and good operation and management of Duke Energy Carolinas' fossil fleet during the test period.

Q. DURING THE TEST PERIOD, HOW DID THE COMPANY'S COAL UNITS PERFORM AS COMPARED TO THE INDUSTRY?

A. Duke Energy Carolinas has long been an industry leader in achieving low heat rates, which indicates an efficient generating system that uses less heat energy from fuel to generate electrical energy. Duke Energy Carolinas' Belews Creek Steam Station and Marshall Steam Station consistently rank among the most efficient coal plants in the nation. As an example, in the January/February 2009 issue of *Electric Light and Power* magazine, Duke Energy Carolinas' Belews Creek Steam Station and Marshall Steam Station ranked as the country's third and sixth most energy efficient coal-fired generators, respectively.

The system coal units achieved a fleet-wide equivalent availability factor of 84.7% for the test period and 89.5% during the summer peak months. These results are comparable with the most recently published NERC average equivalent availability for all North American coal plants of 84.8%. This NERC availability

average covers the period 2003-2007 and represents the performance of over 800 North American coal-fired units.

Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S HYDROELECTRIC FACILITIES DURING THE TEST PERIOD.

A. The hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 89.2% and with an excellent low forced outage factor of 0.9%. Absent the impact of drought-related restrictions, this system availability factor was 92.8% with a forced outage factor of 0.8%.

IV. KEY DRIVERS IMPACTING O&M COSTS

A. NUCLEAR GENERATION COSTS AND CHALLENGES

Q. WHAT ARE THE SIGNIFICANT COSTS IMPACTING OPERATIONS AND MAINTENANCE EXPENSES FOR NUCLEAR OPERATIONS?

A. Operations & Maintenance ("O&M") expenditures for the Company's nuclear facilities are made up of both fuel and non-fuel items. In 2008, Duke Energy Carolinas' nuclear fleet had the lowest total operating cost for the industry, as compared to other large fleet operators, based on Electric Utility Cost Group ("EUCG") cost and performance results. EUCG is an industry group that provides member utilities a high-level industry view of their own station performance in relation to the industry. The Company's 2008 average total operating cost, which includes operating and maintenance, administration, and fuel costs, was $19.26/megawatt-hour. During the test period, approximately 26% of the required O&M expenditures for the nuclear fleet were fuel related. A complete discussion of nuclear fuel costs in the current fuel proceeding review period can be found in

Company Witness Culp's testimony filed with this Commission in Docket No. 2009-3-E.

Non-fuel items comprise the remainder of O&M expenditures for the nuclear fleet. Nuclear power plant operations are very labor intensive and therefore, a significant portion of O&M costs are related to internal and contracted labor. As a result of the Company's increased ownership interest in the Catawba Nuclear Station, O&M costs will increase approximately $17 million annually. Company Witness Stillman addresses the accounting treatment for deferral of certain of these costs. The Company expects to experience continued upward pressure on these ongoing labor costs. In addition, Duke Energy Carolinas expects labor costs to increase approximately $7 million annually due to workforce increases necessary to comply with the U.S. Nuclear Regulatory Commission's revision to its 10 CFR Part 26 rule ("the fatigue rule"). The fatigue rule places restrictions on the number of hours covered personnel may work at a nuclear facility. The revisions are intended to enhance fitness for duty ("FFD") for personnel at nuclear power plants and include new requirements for work hour limits, break limits and minimum time-off between shifts for work groups that perform covered work.

The Company has incurred additional expenses for the purposes of augmenting our existing workforce pipeline development programs to address our aging workforce. Since 2006, the Company has spent approximately $1 million annually on pipeline program expenses for development of our future engineering and skilled nuclear workforce. These programs currently include the Spartanburg Community College and Engineering Intern programs. Duke Energy Carolinas partnered with Spartanburg Community College ("SCC") to develop an Associate's

Degree Program in Radiation Protection Technology. This two year program at SCC provides a steady source of radiation protection technician candidates. Likewise, the Engineering Intern Program assures a pipeline of replacement engineers by providing internships to regional university engineering students. Due to the demand for skills and age demographics, additional programs are being considered for development of nuclear operators and maintenance technicians in partnership with Gaston College. Expenses for these additional programs are expected to be commensurate with existing costs.

Other significant non-fuel costs are NRC fees that nuclear owners and operators pay annually pursuant to (1) Part 170, which covers review of applications for new licenses, renewal applications, amendment requests, and inspections, and (2) Part 171, which provides for recovery of regulatory and other generic costs. These fees are expected to increase in 2009. In June 2009, the NRC issued its final FY2009 Fee Rule in the Federal Register (74 FR 9130) indicating (1) an increase in the hourly rate for Part 170 fees for both the reactor and materials programs and (2) an increase in the Part 171 annual license fee that nuclear operators pay per reactor. The reactor license fee is expected to be retroactive to the beginning of the government fiscal year beginning October 2008. The increased NRC fees as currently proposed, along with increases in required INPO and NEI fees, will cost the Company in excess of $5 million annually. Other non-fuel costs include project-related costs and material and employee expenses.

Q. **WHAT INITIATIVES HAS THE COMPANY TAKEN TO INCREASE EFFICIENCIES IN NUCLEAR OPERATIONS?**

A. The Company uses competitive benchmarking, long-range planning, work prioritization tools, and other processes to continuously improve operational and cost performance. Over the years, efficiencies have been gained from the implementation of common policies, practices, and procedures across the Duke Energy Carolinas nuclear fleet. In addition, efficiencies are sought through incorporation of industry best practices.

In the mid-1990s, Duke Energy Carolinas used a strategy that involved reducing unit output in order to conserve fuel so that the Company could avoid refueling during peak summer months. The Company has since been able to shorten and align refueling outages by increasing the length of fuel cycles, thereby ensuring that the nuclear units are available during peak periods when replacement power costs are very high. As a result of this and improved forced outage rates, the Company's nuclear fleet capacity factor has increased from 72% in the last general rate case to highs at or above 90% for the last nine consecutive years. The alignment of refueling outages also has allowed the Company to manage contractor costs by optimizing the use of contract labor as these resources are moved from site to site.

Currently, nuclear generation is working closely with major supplemental workforce providers to increase the number of local workers being utilized across the nuclear fleet, when individuals with needed skills are available. Traditionally, the nuclear industry has heavily utilized workers who travel from site to site to provide outage and other supplemental labor. These workers are typically eligible for per diem living expenses when their permanent home is greater than fifty miles

from the assigned work location. This initiative serves to improve the local economy and reduce nuclear operations costs. Overall, these efforts result in improved fleet reliability and efficiency on a cost per KW generated basis.

Q. WHAT CHALLENGES DOES DUKE ENERGY CAROLINAS FACE AS TO ITS NUCLEAR OPERATIONS?

A. Despite the success of the Company's efficiency initiatives, we continue to face upward pressure on O&M costs including escalation of labor costs, as discussed above. Duke Energy Carolinas is working with community colleges in North Carolina and South Carolina to offer training programs to help attract and prepare the needed, skilled workforce. In addition, the costs to perform maintenance work necessary to address reliability and regulatory concerns are increasing due to rising costs for materials and supplies.

As Witness Turner testified, one of the most significant challenges facing our industry is the cost and technological obstacles of compliance with anticipated climate change legislation. Nuclear energy emits zero greenhouse gases, has a demonstrated safety record, it is efficient and economical, and the basic technology is available today. Therefore, maintaining our existing nuclear fleet and adding additional nuclear capacity is critical to realistically attaining significant levels of carbon emissions reduction.

B. FOSSIL-HYDRO COST AND CHALLENGES

Q. WHAT ARE THE SIGNIFICANT COST DRIVERS IMPACTING OPERATION AND MAINTENANCE EXPENSES FOR THE FOSSIL-HYDRO FLEET?

A. O&M expenditures for the Company's fossil and hydro facilities are made up of both fuel and non-fuel items. For the fossil units, approximately 85% of these required O&M expenditures are fuel-related (primarily coal, but also natural gas, fuel oil, environmental reagents, and net proceeds from sale of by-products). A complete discussion of fossil fuel and fuel-related costs in the current fuel proceeding review period is included in the testimony of Company Witnesses Stroud and Roebel filed with this Commission in Docket No. 2009-3-E. Non-fuel items comprise the remainder of these O&M expenditures for the fossil and hydro facilities. The majority of these non-fuel expenditures are for labor costs from Company or contract resources to operate, maintain, or support the facilities.

Duke Energy Carolinas will incur additional non-fuel O&M costs over the next three years in order to operate and maintain the environmental control equipment and new generation resources I discussed above. Over the last several years we have seen rapid and substantial increases in labor, material, and contract services required for the operation and maintenance of these new and existing facilities. The recent economic downturn has moderated these increases; however, we will continue to be challenged by high costs for these products and services driven by market demand, limited availability of commodities and skilled technical and craft resources, in addition to inflationary pressures. The Company will

continue to review these costs and their drivers, and pursue initiatives that optimize the use of funds for the greatest benefit to overall cost and reliability.

Q. WHAT STEPS HAVE FOSSIL-HYDRO OPERATIONS TAKEN TO CONTROL COSTS AND MITIGATE THE IMPACT OF THE INCREASES YOU DISCUSSED?

A. Duke Energy Carolinas has maintained a continuous focus on improving operational results and cost effectiveness in operation of its fossil-hydro fleet since the 1991 rate case. Although these improvement programs have changed in name over the years, the focus is always placed on evaluating processes and technological advancements that can be consistently deployed throughout the fleet that allow personnel to improve skills, adapt to change quickly, and generate ideas that can be implemented for further improvement. These improvement initiatives over the years have resulted in a higher-performing and leaner organization, a culture of continuous improvement, and a more cost effective operating structure.

As a current example, the Fossil-Hydro Generation Excellence Program provides each station with a structured process for identifying and evaluating cost savings or process improvement ideas, initiating projects to implement these improvement ideas, measuring results, and sharing of ideas with other stations for implementation as applicable. These efforts support the overall goals of the program to establish a culture of proactively striving for continuous improvement throughout the generation fleet and to work collectively to achieve higher standards through continuous and lasting improvement.

In addition to these continuous improvement and cost reduction efforts, by virtue of operating a larger fleet the fossil-hydro organization has the opportunity to

expand its understanding and sharing of best practice and process improvement ideas. Further, sharing of technical resources and other support functions results in overall cost savings for the organization. The following examples demonstrate how aligning our organization to serve customers of each of our operating companies has improved operations and cost effectiveness:

- Sourcing teams evaluate combined needs for significant purchases of materials and services, creating savings opportunities due to buying power/leverage, streamlined procurement, etc.
- Process improvement initiatives are integrated, allowing for a broader application of effective cost savings ideas and best practices.
- Technical expertise is leveraged over a larger fleet, allowing for a more cost effective engineering/technical support structure.
- Environmental health and safety practices can be consistently applied across a larger fleet, ensuring best practices are employed in these critical areas.

These improvement initiatives result in a higher-performing and leaner organization, a culture of continuous improvement, and a more cost effective operating structure. However, despite these efforts the Company continues to face the impacts of new costs and inflationary pressures that are not offset by new revenues due to flattening load growth.

Q. WHAT CHALLENGES DOES DUKE ENERGY CAROLINAS FACE AS TO ITS FOSSIL-HYDRO OPERATIONS?

A. With the significant additions of environmental control equipment that have been required by federal, state or local regulatory mandates, one of the biggest challenges

for the fossil-hydro fleet will be to effectively incorporate the operation and maintenance of this equipment into the overall management of the fleet. As these equipment additions are placed in service we must diligently expand and execute continuous improvements efforts related to the availability and reliability of the fleet, and cost control. As discussed by Witness Turner, we anticipate additional environmental legislation and regulations will be enacted, which will intensify these challenges. Our focus on generation excellence, process improvement, and cost control also will be critical as older generating units are retired and new generating units are placed in service.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT DUKE ENERGY CAROLINAS' GENERATION OPERATIONS, INVESTMENTS, AND COST MANAGEMENT.

A. In summary, Duke Energy Carolinas continues to safely operate its generation assets in a manner that appropriately balances affordability, reliability, and environmental stewardship. Since 1991, we have invested approximately $6 billion in our generation fleet for additions and capital improvements necessary to safely provide reliable electric service to our customers in full compliance with NRC and environmental requirements. Our operational track record demonstrates that we have been successful in the balance we have struck and continue to strike on these key attributes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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Selected Publications, Patents

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- M. Hill, R. Ziolkowski and J. Papapolymerou, "A high-Q Reconfigurable Planar EBG Cavity Resonator," IEEE Microwave and Wireless Components Letters, vol. 11, No. 6, pp. 255-257, June 2001
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52-00-06.0014

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

Form 10-K

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

For the fiscal year ended December 31, 1978—Commission File Number: 1-4928

DUKE POWER COMPANY

(Exact name of Registrant as specified in its charter)

North Carolina	56-0205520
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
422 South Church Street Charlotte, North Carolina	28242
(Address of principal executive offices)	(Zip Code)

704-373-4037

(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
Preference Stock, par value $100	
6¾% Convertible Series AA	New York Stock Exchange
Preferred Stock, par value $100	
8.70% Series F	New York Stock Exchange
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
8.84% Series M	New York Stock Exchange
Preferred Stock A, par value $25	
10.76% Series 1975	New York Stock Exchange
First and Refunding Mortgage Bonds:	
7⅜% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7⅜% Series B Due 2002	New York Stock Exchange
7¾% Series Due 2003	New York Stock Exchange
8⅛% Series B Due 2003	New York Stock Exchange
9¾% Series Due 2004	New York Stock Exchange
9½% Series Due 2005	New York Stock Exchange
8⅜% Series Due 2006	New York Stock Exchange
8⅛% Series Due 2007	New York Stock Exchange
9⅛% Series Due 2008	New York Stock Exchange
13% Notes due September 1, 1979	New York Stock Exchange

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

Preferred Stock, par value $100

(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X. No_____.

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the close of the period covered by this report.

Common stock, no par—72,132,229 shares

PART I

Item 1 Business

THE COMPANY

The Company is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,000,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina, and Greenville, Spartanburg and Anderson in South Carolina. During 1978 the Company's electric revenues amounted to approximately $1.4 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks ninth in the United States among investor-owned utilities in kilowatt-hour sales.

The electric utility industry in general has been experiencing problems in a number of areas including the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts by opposition groups to delay or prevent construction of nuclear generating and related facilities and to limit the use of existing facilities; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; difficulty in obtaining sufficient capital on reasonable terms; difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

SERVICE AREA

The Company supplies electric service directly to approximately 1,222,000 customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to 37 other incorporated municipalities and to a number of rural electric cooperatives and private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of them.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco and furniture industries are of major significance to the economy of the area and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, chemicals, food products, and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $233 million of the Company's revenues for 1978, representing 17% of electric revenues and 52% of electric industrial revenues.

ENERGY REQUIREMENTS AND CAPABILITY

The total capability of the Company's generating facilities at December 31, 1978 was 12,322,000 KW without reduction to reflect the possible unavailability or reduced capability of facilities at any given time because of regulatory restrictions, scheduled maintenance or repair requirements. Of this total capability, 2,580,000 KW were provided by nuclear units; 7,622,000 KW were provided by coal-fired steam stations; 1,452,000 KW were provided by 26 hydro-electric stations; and 668,000 KW were provided by combustion turbine and combined cycle units (using oil and gas).

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1978-1979 winter peak load of 9,844,000 KW occurred on January 4, 1979. The 1977-1978 winter peak load of 9,690,170 KW occurred on February 7,1978, and the 1978 summer peak load of 9,472,205 KW occurred on June 28, 1978.

CONSTRUCTION PROGRAM

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of the Company's load forecasts, financial condition (including cash flow, earnings and levels of relief in rate proceedings), the availability and cost of capital in the financial markets, the availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise and changing regulatory and environmental standards. The estimates of construction costs and the timing of construction expenditures are also subject to the sale of all or a portion of the Company's remaining interest in the Catawba Nuclear Station. The Company is keeping its construction program as flexible as possible in order to accommodate any variations as a result of such considerations.

Costs for the construction program, including the acquisition of nuclear fuel, for 1979, 1980 and the three-year period 1979-1981, as now scheduled, are currently estimated, assuming no further sale of any portion of the Company's remaining interest in the Catawba Nuclear Station, as follows (in thousands of dollars):

Type of Facilities	1979	1980	1979-1981
Generation	$596,000	$598,000	$1,751,000
Transmission	46,000	58,000	176,000
Distribution	76,000	87,000	270,000
Other	63,000	71,000	199,000
Total	$781,000*	$814,000*	$2,396,000*
Nuclear Fuel	$126,000	$152,000	$ 491,000

*The Company's procedures for estimating construction costs (which include the allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, and allowances for

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inflation utilizing Bureau of Labor Statistics indices. Effect has also been given to legislation in North Carolina requiring, for ratemaking purposes, the inclusion in the rate base of construction expenditures incurred after July 1, 1979 in rate applications filed on or after such date which will result in lower construction costs due to a corresponding reduction in the allowance for funds used during construction.

The Company is continuing to experience increases in the cost of construction of new facilities as a result of recurring rises in the costs of materials, labor and capital, and increasing capital requirements for environmental purposes. However, the Company believes that in recent years it has been able to construct generating units at a lower cost per KW than generally experienced by other utilities for units of comparable type and vintage.

The construction program, as now scheduled, reflects decisions to defer the operating dates of generating facilities occasioned primarily by reductions in forecasts of energy demands and difficulties in meeting capital requirements. The Company has also experienced construction delays resulting from late delivery of equipment, design changes and difficulties encountered in installation of equipment. Such delays have recently resulted in the deferral from mid-1979 to early 1980 of the operating date of Unit No. 1 of the McGuire Nuclear Station. Although such deferrals may, in certain instances, have resulted in near-term expenditure reductions, cost escalations and general inflationary price trends will, over the long term, increase construction costs per KW.

The Company is currently engaged in a comprehensive load management program designed to encourage a shift in consumption of energy from on-peak to off-peak periods and to restrain the growth of its peak demand in order to minimize the magnitude of future construction and maximize reserve margins of generating capability already scheduled. Such program, which is designed to reduce the growth in peak demand by approximately 1,768,000 KW through 1990, includes, among other things, promotion of energy efficient building structures and appliances, use of residential conservation rates, possible use of interruptible rates for large customers, possible control by the Company of residential customers' electric water heaters and air conditioners during peak demand periods, and time-of-day pricing an experimental basis to a limited number of customers. The company has premised its current construction program on such load management program which the Company believes has resulted in an estimated reduction in its most recent peak load of approximately 368,000 KW.

Through 1981 the Company estimates a minimum reserve margin of approximately 19% above its anticipated peak load requirements.

During the five-year period 1974-1978, gross property additions (including nuclear fuel) and net retirements amounted to approximately $2.8 billion and $346 million, respectively, resulting in a net increase of approximately $2.5 billion, or 73%, in gross plant. Net retirements include the interest in the Catawba Nuclear Station sold to the North Carolina Municipal Power Agency Number 1.

The following table sets forth the major generating facilities (all nuclear) of the Company currently under construction which are to be added to its present generating capability of 12,322,000 KW (dollars in thousands):

Unit and Location	Net KW Capability	Date of Planned Operation*	Estimated Construction Cost Per KW**	Total Estimated Construction Costs**	Amounts Expended Through 12-31-78
McGuire No. 1	1,180,000	1980	$543	$1,280,833	$935,000
McGuire No. 2 (Northwest of Charlotte in NC)	1,180,000	1981			
Catawba No. 1	1,145,000	1981	665	951,445***	393,000***
Catawba No. 2 (Southwest of Charlotte in SC)	1,145,000	1983			
Cherokee No. 1	1,280,000	1985			
Cherokee No. 2	1,280,000	1987	950	3,649,772	176,000
Cherokee No. 3 (Northeast of Spartanburg in SC)	1,280,000	1989			

*Operational dates may vary due to changes in load forecasts, construction delays, difficulties which may be encountered in obtaining regulatory approvals and other factors. The Company is currently reassessing the scheduled operating dates for Unit No. 2 of the McGuire Nuclear Station and both units of the Catawba Nuclear Station in light of the difficulties encountered in meeting the pre-operational testing schedule for Unit No. 1 of the McGuire Nuclear Station which have resulted in a deferral of the operating date of such Unit from mid-1979 to early 1980.

**Excludes initial fuel cores.

***These amounts do not include the costs of a 75% undivided interest in Unit No. 2 and 37½% undivided interest in the support facilities recently sold to the North Carolina Municipal Power Agency Number 1. The Company is currently negotiating to sell to certain of its wholesale customers the balance of Unit No. 2 and all or a portion of Unit No. 1.

In order to reduce its need for external financing, the Company, in November 1978, sold to the North Carolina Municipal Power Agency Number 1 (Agency), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit No. 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. The sale was at a cost plus a profit associated with the interest sold, and the initial payment at the time of closing was $278.4 million which included the initial monthly progress payment. The Company will continue to construct Unit No. 2, and the Agency will finance its portion of the construction costs by continued monthly progress payments. The transaction contemplates that the Company will operate the unit, interconnect its transmission system with it, wheel a certain portion of the capacity and energy of such unit to the municipal participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the municipal participants, and provide supplemental power as required by the Agency to enable it to provide service on a firm basis to the

participating municipalities. The Company will also maintain a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station commencing as early as 1981 under certain circumstances.

The Company has offered to sell to its South Carolina municipal customers the remaining 25% interest in Unit No. 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to the Agency. A group of such municipalities has formed a joint agency, Piedmont Municipal Power Agency, under legislation recently enacted by the South Carolina General Assembly. A lawsuit testing the constitutionality of this legislation is expected to be filed shortly. Any such sale would be subject to obtaining the necessary financing and regulatory approvals.

The Company is also negotiating with a group of its cooperative customers to sell Unit No. 1 of the Catawba Nuclear Station or a portion thereof and up to 50% of the support facilities of such Station. Any such sale would be subject to obtaining the necessary financing and regulatory approvals.

During 1978 the Agency's participating municipalities, which are presently wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and the proposed purchasers of the balance of Unit No. 2 accounted for approximately 2% of KWH sales and approximately 2% of revenues. The proposed purchasers of Unit No. 1 of the Catawba Nuclear Station accounted for approximately 6% of KWH sales and approximately 5% of revenues. There is no assurance that such proposed sales will be consummated and, to the extent that such sales are not consummated, the Company intends to complete and operate such Units as part of its system.

The Company presently plans to construct an additional nuclear generating facility, southwest of Winston-Salem in North Carolina, to be known as the Perkins Nuclear Station. Such facility, which would be virtually identical to the Cherokee Nuclear Station, would consist of three generating units planned for commercial operation in the 1990s. The total cost, exclusive of nuclear fuel costs, is expected to approximate $5 billion, of which $9.5 million was expended through December 31, 1978 and approximately $1.4 million is expected to be incurred in 1979.

The foregoing estimates of construction costs for the generating facilities of the Company presently under construction or in the planning stage reflect for the first time the estimated effects of legislation in North Carolina requiring, for ratemaking purposes, the inclusion in the rate base of construction expenditures incurred after July 1, 1979 in rate applications filed on or after such date. If effect were not given to the implementation of such legislation, the estimated costs for the McGuire and Catawba Nuclear Stations would be approximately the same, and the estimated costs for the Cherokee and Perkins Nuclear Stations and the Bad Creek Hydroelectric Station would be approximately 13% to 14% greater. Generally speaking, the inclusion in the rate base of such construction expenditures will provide a basis for an increase in rates in the three-year period 1979-1981 but not in material amounts.

RATE MATTERS

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSC) must approve the Company's rates for retail sales within the respective states. The Federal Energy Regulatory Commission (FERC) must approve the Company's rates for sales under its wholesale rate schedules.

Increases in base rates since January 1, 1978, all of which were implemented September 1, 1978, are as follows (dollars in thousands):

Rate Schedule	Percent Increase	Revenue Recorded In 1978	Annualized On 1978 Sales
N. C. Retail	5.27	$12,700	$42,000
S. C. Retail*	10.26	8,600**	25,000**
Wholesale*	5.61	2,500	9,000
		$23,800	$76,000

*Subject to refund with interest.
**Reflects approximately 70 percent of amount collected.

Although the Company has recently received a rate increase for its North Carolina retail customers, due to continued inflation it has not been able to earn the rate of return allowed by the NCUC in rate orders based essentially on past test years. As a result, the Company filed an application on March 9, 1979 with the NCUC to increase retail revenues by approximately 4%. If approved, such rates would produce additional revenues of approximately $35.5 million based on the test year ended December 31, 1978. As required by the NCUC, the application was accompanied by a certificate from the Company that the requested increase is within the President's anti-inflation standards.

Fuel Charges. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. Procedures for South Carolina retail customers and wholesale customers entail 60 to 90-day lags from the date fuel expense changes occur until they are reflected in bills to such customers. The NCUC limits changes in the fuel cost component of rates to six-month intervals except in instances where the costs fluctuate above or below the fuel cost component included in rates by more than one mill per KWH. The NCUC also will review the operation of base load generating facilities at semiannual hearings if the nuclear units or the coal-fired units of the Company generate at a capacity factor of less than 60% or 55%, respectively, in which event the Company has the specific burden of justifying the recovery of its incremental fuel costs.

In 1978 both the NCUC and the PSC issued orders essentially requiring the Company to defer as development costs the difference between the price paid for coal purchased from a supplier financed by the Company and that purchased from non-affiliated suppliers. The Company has recently recorded an after tax charge of approximately $10 million to reflect a reduction in the carrying value of the investments that have been made pursuant to the terms of a coal supply contract with such supplier.

Recent Developments. Legislation was enacted in North Carolina in 1977 requiring that capital expenditures for construction work in progress (CWIP) incurred after July 1, 1979 be included in the rate base for ratemaking purposes at the time of any subsequent rate application. Under such legislation, utilities would be permitted to continue to capitalize the composite carrying cost of capital funds used to finance construction (allowance for funds used during construction) with respect to CWIP not so included in the rate base but would not be permitted to do so with respect to CWIP included in the rate base. The legislation also requires that for ratemaking purposes the NCUC utilize, in any rate application filed on or after July 1, 1979, "reasonable original cost" in valuing utility assets instead of the current "fair value" standard.

Several bills have been introduced in the South Carolina General Assembly which, if enacted, would prohibit the Company from utilizing fuel surcharges on its rate schedules and eliminate its present ability to collect rate increases subject to refund pending approval by the PSC. The Company cannot predict whether such legislation will be adopted, but if such legislation is adopted, it could have a materially adverse effect on the Company.

FUEL SUPPLY

The Company presently relies principally on coal for the generation of electric energy, but it has relied on nuclear power to a greater extent in recent years and anticipates doing so in the future. The Company's reliance on oil and gas is minimal.

The Company obtains its coal under long-term supply contracts, through its own mining operations and by open market purchases. During 1978 the Company's coal requirements were supplied approximately as follows: 55% (7.6 million tons) under long-term contracts, 12% (1.7 million tons) from its own mining operations and 33% (4.6 million tons) by open market purchases.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1980 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. In order to further assure its coal supply, the Company has invested in independent coal mining operations located in eastern Kentucky and has arranged the financing of a coal mining operation located in southern West Virginia.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. The Company purchased coal on a spot basis at an average delivered cost of $32.67 per ton, or 136.4¢ per million BTU, in 1978, as compared with an average delivered cost of $30.58 per ton, or 127.6¢ per million BTU, in 1977. However, the Company has recently experienced a modest decline in the cost of coal purchased on a spot basis which contrasts with its recent experience under its long-term contracts. The Company's recoverable coal reserves from its own mining operations is estimated at 240,600,000 tons as of December 31, 1978.

The average cost per million BTU of coal burned by the Company increased substantially during the five-year period 1974-1978 as follows: 1974 - 91.69¢; 1975 - 115.45¢; 1976 - 110.80¢; 1977 - 127.95¢; and 1978 - 144.46¢.

Federal legislation relating to the regulation of surface mining of coal was enacted in 1977. Such legislation, among other things, establishes standards restricting the surface mining of coal, requires the restoration of lands affected by surface mining and imposes a tax based upon the tonnage of coal mined to be used for the restoration of abandoned surface-mined areas. This legislation is adversely affecting the price of coal to the Company. During 1978 approximately 42% of the Company's coal supply was provided by surface mining operations. However, it is anticipated that less coal will be provided through such operations in the future.

As the Company is heavily dependent on coal for the generation of electricity, it is currently endeavoring to maintain an average coal supply of approximately 90 days.

Nuclear. The Company has contracted for uranium materials and services required to fuel its Oconee, McGuire and Catawba Nuclear Stations (see "ENERGY REQUIREMENTS AND CAPABILITY" and "CONSTRUCTION PROGRAM") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1985	1985	2004	1988
McGuire	1985	1985	2004	1988
Catawba	1985	1985	2009	1988

The Company also has commitments, based on the present enrichment policies of the Federal government and the scheduled commercial service dates for its nuclear stations, including its Cherokee and Perkins Nuclear Stations, for approximately 45% of its required uranium materials and approximately 40% of its required conversion services for these facilities from 1985 through 1990. In addition, the Company has commitments for substantially all of the enrichment services required for units of its Cherokee and Perkins Nuclear Stations through the year 2000.

A major portion of the Company's commitments for uranium materials and services included in the foregoing table, as well as a major portion of its other commitments for nuclear fuel for use after 1985, is expected to be obtained from Canadian sources, which must secure permits and export licenses before making deliveries to the Company.

The Company is currently purchasing uranium material at an average price of approximately $18 per pound. However, such price is expected to be substantially greater in future years. The Company's material nuclear supply contracts generally contain force majeure provisions and provide for price escalation under certain conditions.

The Company is endeavoring to obtain other fuel commitments although it cannot predict whether it will be successful or estimate the costs involved. As a part of its efforts to obtain additional sources of uranium at a reasonable cost, a wholly-owned subsidiary of the Company, Western Fuel, Inc.,

has recently entered into a joint venture in Wyoming with Ogle Petroleum Inc., which is acting as operator. Such venture, which is experimental in nature, is intended to ascertain the feasibility of a new method for extracting uranium ore and is not expected to involve material financial commitments. Preliminary field work has commenced but there is no assurance that this venture will be successful.

Although the reprocessing of spent fuel would make available to the Company an additional 20% of its nuclear fuel needs through 1990, there are currently no commercial reprocessing facilities in operation in the United States, and operations, such as those of Allied General Nuclear Services (AGNS) with whom the Company has a contract for reprocessing services through 1984 for certain of its nuclear stations, cannot commence until appropriate licenses are received from the Nuclear Regulatory Commission (NRC). The utilization of such facilities is dependent upon certain regulatory and policy decisions to be made by the Federal government. The President has announced that he opposes the reprocessing of spent fuel but supports the development of spent fuel storage facilities, and the Department of Energy has announced plans pursuant to which the Federal government would accept unreprocessed spent fuel and assume title to the material and responsibility for its storage and disposal in return for which the Company would pay a one-time charge. If reprocessing of spent fuel becomes available in the future, the stored spent fuel could be retrieved or the Company could receive compensation for the net value of such fuel.

The Company will have adequate facilities for storage in its spent fuel pools at the Oconee Nuclear Station through 1980. In order to maintain its ability to discharge an entire reactor core, however, the Company has recently applied for a license to store spent fuel from the Station in the spent fuel pool at the McGuire Nuclear Station presently under construction. Intervenors have opposed the granting of such license. The Company also has sought approval to alter the existing spent fuel pool at the Oconee Nuclear Station to accommodate increased amounts of spent fuel at a cost of approximately $3 million. In the event such license or approval is not obtained, or is unduly delayed, the Company may have to curtail operations at the Oconee Nuclear Station. The Company is enlarging the capacity of the spent fuel pools at the McGuire and Catawba Nuclear Stations and has redesigned the spent fuel pools at the Cherokee and Perkins Nuclear Stations to accommodate larger amounts of spent fuel. Such modifications, which are estimated to cost about $3.6 million in the Company's 1979-1981 construction program, will enable the Company to have adequate facilities for the storage of its spent fuel until approximately 1990.

REGULATION

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC and the Environmental Protection Agency (EPA) and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities. The coal mining operations of Eastover Mining Company, the Company's coal mining subsidiary, are subject to the Coal Mine Health and Safety Act of 1969.

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1979-1981 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $151 million, including $46 million in 1979 and $53 million in 1980. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing standards limiting such emissions which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans. As a result of remedial action taken at certain of its generating stations in North Carolina, all generating units except for Unit No. 2 of the Belews Creek Steam Station have met, on a test basis, the particulate emission limitation requirements. Equipment is being installed at such Unit No. 2 in order to achieve compliance.

The Company petitioned the Environmental Management Commission of the Department of Natural Resources and Economic Development of North Carolina in October 1978 for a variance from and an amendment to its maximum particulate emission limitations. The Company believes that it cannot consistently meet such limitations with equipment currently installed in its coal-fired generating stations, and, unless the limitations are amended or a variance is obtained, expenditures of as much as $560 million may be required during the useful lives of the stations to achieve compliance. In the event the Company is not successful in its petition, noncompliance penalties may be incurred until such additional equipment is installed and such units, which represent approximately 70% of the Company's steam generating capability, may not be operated at full capability or may be unavailable for use from time to time. The North Carolina particulate emission limitation standards are substantially more stringent than those of surrounding states with which the Company would be in compliance. In view of the magnitude of the capital investment which would be required and the relatively limited benefit that would be derived (the Company's existing precipitators remove approximately 99% of the particulate matter), the Company believes that it has a good basis for its requests.

In 1974 EPA issued regulations, applying to the construction or expansion of facilities commenced after June 1, 1975, establishing a mechanism for "prevention of significant air quality deterioration" in areas where air pollution levels of sulfur dioxide and particulate matter are below the national ambient air quality standards. Amendments to the 1970 Act, adopted

in 1977, include, among other things, requirements substantially similar to such regulations. The amendments also require EPA to establish stringent restrictions on emissions in non-attainment areas, to update new source performance standards for specified pollutants and to require the use of the best available technology rather than clean fuels to control emissions. The amendments also authorize EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and new civil penalties of up to $25,000 per day of violations for facilities found to be in violation of an applicable implementation plan. In September 1978 EPA promulgated new performance standards under these amendments which will apply to all stations not presently under construction and will require the use of scrubbers to remove sulfur dioxides, as well as other techniques to remove nitrogen oxides and particulate matter emissions. These amendments and proposed standards will affect the lead time, size and siting of future fossil-fueled generating stations as well as the type, complexity and cost of pollution control equipment to be used.

The Federal Water Pollution Control Act Amendments of 1972 (the 1972 Act) provided for the imposition of effluent limitations to regulate discharges of pollutants, including heat, into the waters of the United States. The 1972 Act mandated that there be achieved by July 1, 1977, with respect to existing plants, effluent limitations requiring application of the "best practicable control technology currently available" as well as compliance with state water quality standards. The Company has complied with these requirements. Regulations proposed under the 1972 Act also prescribed that the location, design and construction of cooling water intake structures reflect the "best technology available for minimizing environmental impact".

The 1972 Act required permits to ensure compliance with its provisions. The Company has received such permits for all of its generating stations either from EPA or under the permit programs of the States of North Carolina and South Carolina which have been approved by EPA.

In 1974 EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines required certain limitations on chemical discharges and imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit (Appalachian Power Company, et al., v. Train). In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement and certain chemical limitations. The Company is unable at this time to determine what effect these developments will have on its operations.

In 1977 Congress adopted the Clean Water Act of 1977 (the 1977 Act) which amended the 1972 Act. The 1977 Act provides for three categories for controlling pollution: (1) conventional pollutants will require treatment by the best conventional pollutant control technology by July 1, 1984; (2) toxic pollutants will require application of the best available technology economically achievable by July 1, 1984, and (3) non-conventional pollutants will require application of the best technology economically achievable within three years after effluent limitations are established, but no later than July 1, 1987. The 1977 Act also authorizes EPA to publish regulations to

control station site runoff, spillage, leaks, sludge or waste disposal, and drainage from raw material storage which is associated with or ancillary to the source. The Company is presently unable to determine the effect, if any, such new legislation will have on its operations until the required regulations are promulgated.

North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. South Carolina has recently proposed regulations implementing its Hazardous Waste Management Act. The Company is unable to determine the effects, if any, that such regulations will have on its operations.

The Company is subject to the Toxic Substances Control Act and the rules and regulations promulgated thereunder relating to the disposition of fly ash. The Company is also aware that certain of its activities may be subject to the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, pursuant to which EPA is presently promulgating regulations. The Company is unable to determine the effects, if any, that such regulations will have on its operations.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations permit public intervention with respect to such issues in proceedings relating to applications for permits or licenses. The operating licenses for the Oconee Nuclear Station and the contruction permits for the McGuire, Catawba and Cherokee Nuclear Stations were granted after completion of the environmental review required of the NRC under the National Environmental Policy Act of 1969.

The Company has insured against public liability claims resulting from nuclear incidents by purchasing the maximum available private insurance of $140 million, and the remaining $420 million of the $560 million limit on liability under the Price-Anderson Act has been provided by an indemnity agreement with the NRC. Effective in 1977 the NRC's indemnity began to be phased out in favor of a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors, and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance and indemnity coverage do not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $225 million, or the insurable value of the facilities, whichever is less. In connection with the sale of a portion of its interest in the Catawba Nuclear Station, the Company placed through a pool

of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of the maximum coverage available.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Certain hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that upon the expiration of any license issued thereunder the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

COMPETITION

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Legislation in North Carolina and South Carolina provides for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. The North Carolina Supreme Court rendered a decision in 1974 which, in some instances, limits the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

EMPLOYEES

On December 31, 1978 the Company employed approximately 17,700 persons, of whom approximately 7,800 were engaged in generating plant construction including design and engineering. About 1,800 electrical operating employees are represented by the International Brotherhood of Electrical Workers with which the Company has a labor agreement which expires on September 30, 1979. The Company's coal mining subsidiary, Eastover Mining Company, employs approximately 1,100 persons, the majority of whom is represented by labor unions, including the United Mine Workers of America.

Item 2 Summary of Operations

DUKE POWER COMPANY
STATEMENT OF EARNINGS

The following Statement of Earnings has been examined by Deloitte Haskins & Sells, independent auditors, whose opinion with respect thereto is included elsewhere herein. The statement should be read in conjunction with its notes and the other financial statements and their notes beginning on page F-3.

	Year Ended December 31				
	1974	1975	1976	1977	1978
	(Dollars in Thousands)				
Electric Revenues (Notes 1 and 2)	$818,803	$930,384	$1,108,358	$1,266,974	$1,396,720
Electric Expenses					
Operation					
Fuel used in electric generation	333,399	338,024	399,770	493,818	543,319
Net interchange and purchased power (credit)	8,495	(11,588)	(28,815)	(318)	17,271
Wages, benefits and materials	92,732	105,890	118,834	139,674	155,443
Maintenance of plant facilities	33,527	40,968	45,369	61,874	78,605
Depreciation and amortization (Note 1)	83,914	100,995	110,644	114,974	120,839
General taxes	64,710	75,757	85,215	95,309	103,816
Income taxes (Notes 1 and 8)	55,380	92,542	143,924	131,757	140,426
Total electric expenses	672,157	742,588	874,941	1,037,088	1,159,719
Electric operating income	146,646	187,796	233,417	229,886	237,001
Other Income (Note 1)					
Allowance for all funds used during construction	62,159	54,794	61,725	-	-
Allowance for equity funds used during construction	-	-	-	62,441	87,810
Earnings of subsidiaries, net (Note 3)	299	197	4,582	8,881	9,159
Other, net (deduction) (Note 10)	4,787	(1,666)	265	(658)	16,168
Income taxes - other, net (Notes 8 and 10)	(4,614)	930	640	778	(16,963)
Income taxes - credit (Note 8)	20,708	20,859	22,323	25,513	35,725
Total other income	83,339	75,114	89,535	96,955	131,899
Income before interest deductions	229,985	262,910	322,952	326,841	368,900
Interest Deductions					
Interest on long-term debt	111,130	135,289	144,749	152,496	165,926
Other interest	16,052	10,478	4,502	6,390	6,533
Allowance for borrowed funds used during construction (credit) (Note 1)	-	-	-	(24,394)	(34,160)
Total interest deductions	127,182	145,767	149,251	134,492	138,299
Net Income	102,803	117,143	173,701	192,349	230,601
Dividends on preference and preferred stocks	28,534	34,344	34,990	38,879	46,632
Earnings for Common Stock	$ 74,269	$ 82,799	$ 138,711	$ 153,470	$ 183,969
Common Stock Data					
Earnings per share (Note 4)	$1.74	$1.62	$2.40	$2.41	$2.61
Dividends per share	$1.40	$1.40	$1.525	$1.63	$1.74

Note references are to Notes to Financial Statements.

DE00000439

MANAGEMENT'S DISCUSSION AND ANALYSIS OF THE STATEMENT OF EARNINGS

The following discussion presents management's analysis of the Statement of Earnings with respect to 1978 and 1977 as compared with the respective preceding year.

Electric Revenues and KWH Sales

Electric revenues increased 10% for 1978 reflecting increases in rates implemented during the year and higher KWH sales. The increased rates include the collection of higher revenues through fuel cost adjustment procedures and increases implemented on September 1, 1978 in rate schedules for all three of the Company's regulatory jurisdictions. Electric revenues rose 14% in 1977 over 1976 due to increased customer usage and increased fuel cost adjustment revenues.

The moderate 2.2% growth in KWH sales for 1978 was due principally to an increase in the total number of customers. The 1977 increase in KWH sales was due primarily to severe weather conditions which also had an impact on KWH sales in 1978, but to a slightly lesser degree.

Fuel Used in Electric Generation

The 10% increase in fuel expense in 1978 reflected a continuing escalation in prices of all types of fuels used. With an improvement in the KWH output of the Oconee Nuclear Station and increased purchased energy, fossil-fueled generation decreased from the 1977 level resulting in a 8% decline in the tons of coal burned during 1978.

Fuel expense rose 24% in 1977 due to higher fuel prices plus increased generation from older, less efficient fossil-fueled stations as well as combustion turbine units. The growth in KWH generation was supplied predominately by fossil-fueled stations.

Net Interchange and Purchased Power

During the third quarter of 1978 the Company interchanged and purchased significant amounts of electric energy to alleviate coal procurement problems caused by a railroad strike. In 1977 the Company sold less energy to its neighboring utilities than in 1976. This resulted principally from efforts to maintain adequate coal inventories during periods of coal procurement problems caused by miner strikes and severe weather.

Other Operation and Maintenance Expenses

Other operation expenses increased 11% in 1978 and 18% in 1977 for a number of reasons, including inflation, compliance with more stringent regulatory requirements, additional costs associated with the changing generation mix, increases in salaries, wages and benefits, and higher insurance costs.

Maintenance expenses increased 27% in 1978 and 36% in 1977 primarily due to specific equipment repairs to all categories of generating stations and increased maintenance requirements on the Company's overhead power lines and rights-of-way.

Tax Expense

General taxes increased 9% in 1978 and 12% in 1977 reflecting revenue growth which produced greater gross receipts taxes, and increased payroll taxes resulting from an increase in the effective tax rates, a greater number of employees and higher average compensation levels. The 1978 increase was also due to property tax increases attributable to increased electric plant in service.

The 15% increase in total income tax expense for 1978 ("Electric Expenses" and "Other Income") reflected higher operating income and the tax treatment of the gain on the sale of an interest in the Catawba Nuclear Station. The 13% decrease in total income tax expense for 1977 reflected lower operating income, mainly due to increases in fuel and maintenance expenses.

Other Income

Other income rose 36% in 1978 due to an increase in the allowance for funds used during construction (ADC) attributable to greater investment in construction work in progress (CWIP). (Also see "Interest Deductions - Allowance for borrowed funds using during construction (credit)"). Other income rose in 1977 for a similar reason. The average CWIP in both years increased because, while construction expenditures continued, no generating unit was placed in service in either year.

Other income for 1977 also increased due to higher subsidiary earnings, mainly resulting from lot sales by Crescent Land & Timber Corp.

For 1978 "Other, net (deduction)" and the related income taxes reflect the effect of the sale of an interest in the Catawba Nuclear Station and a reduction in the carrying value of the investments that have been made pursuant to the terms of a certain coal supply contract referred to in note 10 of Notes to Financial Statements. The net effect of such transactions was not material.

Interest Deductions and Preference and Preferred Dividends

To finance its continuing construction program, the Company issued additional securities in both 1978 and 1977, which resulted in combined increases for interest and preferred dividends of 11% for 1978 and 7% for 1977.

Item 3 Properties

For a description of the Company's generating capability, see "Item 1 Business - ENERGY REQUIREMENTS AND CAPABILITY."

At December 31, 1978 transmission lines of the Company consisted of approximately 11,622 circuit miles of various voltages and types of structure, of which approximately 3,000 miles are lines carrying 44,000 volts and under; 5,850 miles are lines carrying 100,000 volts; 2,272 miles are lines carrying 230,000 volts and 500 miles are lines carrying 525,000 volts. The distribution lines consisted of approximately 51,857 miles of wood pole lines and 3,076 miles of underground lines. Transmission and distribution substations in service had a transformer capacity of approximately 50,000,000 KVA and distribution transformers in service had an aggregate capacity of approximately 19,000,000 KVA.

The Company, to supplement its financing sources, has sold and leased back some of its assets such as combustion turbines, office buildings and nuclear fuel. The aggregate of such leases is not material.

Item 4 Parents and Subsidiaries

The Duke Endowment owned approximately 18% of the outstanding common stock of the Company at December 31, 1978. The Duke Endowment is a common law trust, administered by 15 Trustees, 14 of whom constitute all of the Trustees of The Doris Duke Trust, another common law trust, which owned approximately 3% of the outstanding common stock of the Company. A Trustee of The Duke Endowment and The Doris Duke Trust is also a Director of the Company.

The Company owns 100% of the voting securities of all of its subsidiaries. All of such subsidiaries are accounted for on the Company's financial statements by the equity method and, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (see Note 3 of Notes to Financial Statements).

Item 5 Legal Proceedings

In 1976 a proceeding entitled Anne Dickie v. Duke Power Company was instituted in the United States District Court for the Western District of North Carolina on behalf of the plaintiff and on behalf of an alleged class seeking to enjoin the Company from engaging in various employment, promotion, assignment and compensation practices alleged to discriminate against female employees in the Company's operations in Mecklenburg County, North Carolina. The plaintiff also requests, among other things, the implementation of an "affirmative relief" program to correct the effects of past discrimination and prohibit future discrimination and seeks back pay, including benefits, for herself and the alleged class in an unspecified amount. The Court has given its preliminary approval to a proposed settlement agreement with respect to this litigation which, if finally approved, will have no material effect on the Company.

NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating

licenses for nuclear power plants. These regulations permit public intervention with respect to such issues in proceedings relating to applications for permits or licenses. The Company has applied to the NRC for a construction permit for the Perkins Nuclear Station. Active opposition has been encountered at the environmental hearings for such permit, and such opposition is continuing. The NCUC has issued a certificate of convenience and public necessity for such facility, which included certain restrictions requested by the North Carolina Environmental Management Commission on use of water from the Yadkin River. Certain of the intervenors in the proceeding have sought judicial review of the decision of the Environmental Management Commission not to require additional water use restrictions. The Court of Appeals affirmed the decision of the Environmental Management Commission on February 20, 1979. The time for the intervenors to seek further review by the Supreme Court of North Carolina has not yet expired. Certain intervenors are also opposing the Company's application to the NRC for operating licenses for both units of the McGuire Nuclear Station.

Item 6 Increases and Decreases in Outstanding Securities and Indebtedness

(a) Changes in outstanding equity securities:

Common stock, without par value:		
Shares outstanding at December 31, 1977		65,429,972
Shares issued in public offering on March 9, 1978	5,500,000	
Shares issued pursuant to Stock Purchase-Savings Program for Employees on various dates in 1978	623,141	
Shares issued pursuant to Dividend Reinvestment and Stock Purchase Plan on various dates in 1978	260,912	
Shares issued pursuant to Employees' Stock Ownership Plan on various dates in 1978	14,096	
Conversion of 75,383 shares of Preference Stock, 6 3/4% AA, Convertible, $100 par, 4,900 shares at $25.56/share and 70,483 at $24.73/share	304,108	6,702,257
Shares outstanding at December 31, 1978		72,132,229
Preference Stock, 6 3/4% AA, Convertible, $100 par:		
Shares outstanding at December 31, 1977		499,850
Conversion of Preference Stock (see above)		(75,383)
Shares outstanding at December 31, 1978		424,467
Preferred Stock:		
Shares outstanding at December 31, 1977		6,850,000
Preferred Stock, 8.375% Series L, $100 par, issued through private placement June 16, 1978	500,000	
Preferred Stock, 8.84% Series M, $100 par, issued through public sale August 16, 1978	400,000	900,000
Shares outstanding at December 31, 1978		7,750,000

(b) Changes in outstanding debt securities and other debt:

Issuance of First & Refunding Mortgage Bonds, 9 3/8% Series Due 2008	$125,000,000

The information set forth under Item 5B in the Company's Form 10-Q for the quarter ended September 30, 1978 is incorporated herein by reference thereto.

(c) Changes in outstanding debt securities and other debt during the fourth quarter of the fiscal year.

Not applicable.

Item 7 Changes in Securities and Changes in Security for Registered Securities

Not applicable.

Item 8 Defaults upon Senior Securities

Not applicable.

Item 9 Approximate Number of Equity Security Holders

Title of Class	Number of Record Holders at January 31, 1979
Common Stock - Without Par Value	107,678
Preference Stock, $100 Par, 6 3/4% Convertible Series AA	2,118
Preferred Stock, $100 Par, 4.50% Series C	99
Preferred Stock, $100 Par, 5.72% Series D	753
Preferred Stock, $100 Par, 6.72% Series E	620
Preferred Stock, $100 Par, 8.70% Series F	4,097
Preferred Stock, $100 Par, 8.20% Series G	4,076
Preferred Stock, $100 Par, 7.80% Series H	1,744
Preferred Stock, $100 Par, 7.35% Series I	1
Preferred Stock, $100 Par, 8.20% Series J	5
Preferred Stock, $100 Par, 8.28% Series K	375
Preferred Stock, $100 Par, 8.375% Series L	6
Preferred Stock, $100 Par, 8.84% Series M	230
Preferred Stock A, $25 Par, 10.76% Series 1975	7,714

Item 10 Submission of Matters to a Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Office	Service In Such Capacity Since	Age*
Carl Horn, Jr.**	Chairman of the Board and Chief Executive Officer	1976	57
W. S. Lee**	President and Chief Operating Officer and Director	1978	49
D. W. Booth**	Executive Vice President and Director	1976	54
W. H. Grigg**	Senior Vice President, Legal and Finance and Director	1971	46
A. C. Thies**	Senior Vice President, Production and Transmission and Director	1971	57
John D. Hicks**	Senior Vice President, Public Affairs and Director	1971	55
W. H. Owen**	Senior Vice President, Engineering and Construction and Director	1978	52
Keith Arledge	Vice President, Western Division	1973	61
Thomas C. Berry	Vice President, Southern Division	1976	48
William J. Burton	Vice President, Corporate Communications	1972	65
Henry L. Cranford	Vice President, Central Division	1973	51
L. C. Dail	Vice President, Design Engineering	1978	53
Donald H. Denton, Jr.	Vice President, Marketing	1975	41
Robert L. Dick	Vice President, Construction	1971	51
Steve C. Griffith, Jr.	Vice President and General Counsel	1977	45
Porter A. Hauser	Vice President, Financial Administration	1976	61
E. N. Hedgepeth, Jr.	Vice President, Distribution Engineering, Construction and Operations	1978	51
Frank A. Jenkins	Vice President, Transmission	1971	59
J. Wesley Lewis	Vice President, Division Operations	1971	63
Joe S. Major, Jr.	Vice President, Personnel	1971	58
Joseph G. Mann	Vice President, Northern Division	1973	55
Paul H. Mann, Jr.	Vice President, Operation	1978	56
William O. Parker, Jr.	Vice President, Steam Production	1974	54
Thomas M. Patrick, Jr.	Vice President, Eastern Division	1973	58
George W. Ferguson, Jr.	Secretary	1975	46
Richard C. Ranson	Treasurer	1976	37
William R. Stimart	Controller	1976	47

*As of March 23, 1979
**Members of the Executive Committee.

Officers serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any directors or executive officers of the Company.

All of the above executive officers have held responsible positions with the Company for the past five years.

Item 11 Indemnification of Directors and Officers

The item as set forth in the Company's annual report on Form 10-K for the year ended December 31, 1975 is hereby incorporated by reference.

Item 12 Financial Statements, Exhibits Filed and Reports on Form 8-K

(a) Documents filed as part of annual report:

1. Financial Statements:
   See index on page F-1.

2. Exhibits:
   I. Computation of Fully Diluted Earnings Per Share
   II. Stock Purchase-Savings Program for Employees (Form 11-K)

(b) Reports on Form 8-K
   Not applicable.

PART II

Items 13 through 15

These items have been omitted pursuant to Instruction H because the Company, subsequent to the close of the fiscal year, has filed with the Securities and Exchange Commission a definitive proxy statement pursuant to Regulation 14A which involves the election of directors.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DUKE POWER COMPANY
(COMPANY)

By W. R. Stimart
W. R. Stimart, Controller

Date: March 28, 1979

DE00000447

DUKE POWER SERVICE AREA

DUKE POWER COMPANY
INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

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The following schedules are omitted as not applicable or not required under Rules of Regulations S-X: I, II, III, IV, VII, VIII, X, XI, XIV, XV, XVII, XVIII, and XIX. Significant information required by Schedules IX, XIII, and XVI is included in the financial statements or the notes thereto.

Financial statements and schedules of the Company's subsidiaries are omitted because all such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

DE00000449

Deloitte
Haskins+Sells

2100 Southern National Center
Charlotte, North Carolina 28202
(704) 372-3560
Cable DEHANDS

AUDITORS' OPINION

Duke Power Company:

We have examined the financial statements and schedules of Duke Power Company, listed in the accompanying Index to Financial Statements, which you are filing as part of your Annual Report (Form 10-K) to the Securities and Exchange Commission for the year ended December 31, 1978. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the above-mentioned balance sheets and statements of capitalization, earnings, retained earnings, and source of funds for plant construction costs present fairly the financial position of the Company at December 31, 1977 and 1978 and the results of its operations and the source of its funds for plant construction costs for each of the five years in the period ended December 31, 1978, in conformity with generally accepted accounting principles applied on a consistent basis; and the schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

Deloitte Haskins + Sells

DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 12, 1979

DUKE POWER COMPANY
BALANCE SHEET
(Dollars in Thousands)

ASSETS

	December 31	
	1977	1978
Electric Plant - at original cost (Notes 1, 5 and 7) (Schedules V and VI)		
Electric plant in service	$3,761,353	$3,964,825
Less accumulated depreciation and amortization	1,068,103	1,239,250
Electric plant in service, net	2,693,250	2,725,575
Construction work in progress	1,538,521	1,844,323
Total electric plant, net	4,231,771	4,569,898
Other Property and Investments		
Other property - at cost (less accumulated depreciation: 1977 - $4,473; 1978 - $4,835) (Schedules V and VI)	21,448	21,623
Investments in and advances to subsidiaries (Note 3)	39,947	23,558
Other investments - at cost or less	8,811	8,759
Total other property and investments	70,206	53,940
Current Assets		
Cash (including time deposits: 1977 - $16,122; 1978 - $17,866) (Note 9)	18,218	20,794
Short-term U.S. government securities	-	17,000
Receivables (less allowance for losses: 1977 - $3,053; 1978 - $3,608) (Schedule XII)	99,708	102,924
Fuel clause revenues accrued (Notes 1 and 2)	14,887	16,672
Materials and supplies - at average cost		
Coal	110,125	122,586
Other	51,567	61,062
Total current assets	294,505	341,038
Deferred Debits		
Debt expense, being amortized over terms of related debt	11,941	11,926
Other	2,283	7,819
Total deferred debits	14,224	19,745
Total assets	$4,610,706	$4,984,621

See notes to financial statements.

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DUKE POWER COMPANY
BALANCE SHEET
(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	December 31	
	1977	1978
Capitalization (see Statement of Capitalization)		
Common stock equity	$1,343,315	$1,537,201
Preference and preferred stocks	554,985	637,447
Long-term debt	1,948,081	1,974,209
Total capitalization	3,846,381	4,148,857
Current Liabilities		
Accounts payable	76,659	112,568
Interest accrued	47,136	53,366
Taxes accrued	33,284	68,993
Other	8,698	9,946
Total	165,777	244,873
Notes payable for construction-pending permanent financing (Note 9)	174,095	-
Current maturities of long-term debt	70,085	149,107
Total current liabilities	409,957	393,980
Accumulated Deferred Income Taxes (Notes 1 and 8)	272,580	313,058
Deferred Credits		
Investment tax credit (Notes 1 and 8)	65,908	111,661
Other (Schedule XII)	15,880	17,065
Total deferred credits	81,788	128,726
Commitments and Contingencies (Notes 7 and 11)		
Total capitalization and liabilities	$4,610,706	$4,984,621

See notes to financial statements.

DE00000452

DUKE POWER COMPANY
STATEMENT OF CAPITALIZATION
(Dollars in Thousands)

	Rate/Series	Shares Outstanding	Redemption Price Per Share: Current	Redemption Price Per Share: Eventual Minimum	December 31 1977	December 31 1978
Common Stock Equity (Notes 3 and 6)						
Common stock, no par, authorized 100,000,000 shares; outstanding 65,429,972 and 72,132,229 shares, for 1977 and 1978, respectively					$1,135,418	$1,271,028
Retained earnings					207,897	266,173
Total common stock equity					1,343,315	1,537,201
Percent of capitalization					34.9%	37.0%
Preference and Preferred Stocks (Note 6)						
Preference stock, $100 par (authorized 1,500,000 shares)	Convertible	499,850	$100.00	$100.00	49,985	
	6 3/4% AA	424,467	$100.00	$100.00		42,447
Preferred stock, $100 par (authorized 5,000,000 shares, 1977; 10,000,000 shares, 1978)	4.50% C	350,000	102.25	101.00	35,000	35,000
	5.72% D	350,000	103.00	101.00	35,000	35,000
	6.72% E	350,000	107.00	102.00	35,000	35,000
	8.70% F	600,000	110.00*	101.00	60,000	60,000
	8.20% G	600,000	107.00	101.00	60,000	60,000
	7.80% H	600,000	107.42	103.52	60,000	60,000
	7.35% I	600,000	110.00*	101.00	60,000	60,000
	8.20% J	500,000	110.00*	102.00	50,000	50,000
	8.28% K	500,000	109.63*	101.35	50,000	50,000
	8.375% L	500,000	108.38*	100.00	-	50,000
	8.84% M	400,000	109.87*	101.03	-	40,000
Preferred Stock A, $25 par (authorized 10,000,000 shares)	10.76%.1975	2,400,000	27.69*	25.25	60,000	60,000
Total preference and preferred stocks					554,985	637,447
Percent of capitalization					14.4%	15.4%
Long-Term Debt (Note 5)	**Rate**	**Due**				
First and refunding mortgage bonds	2 7/8%-11%	1979-2008			1,778,250	1,896,500
Sinking fund debentures	4 7/8%	1982			27,345	25,000
Term notes	6.85%	1978			60,000	-
	13%	1979			100,000	100,000
Pollution control obligations	75% of Prime	1983			2,420	2,500
Turbine generator leases (Note 7)					22,308	25,535
Capitalized leases (Note 7)					28,051	74,951
Unamortized debt discount and premium, net					(208)	(1,170)
Current maturities of long-term debt					(70,085)	(149,107)
Total long-term debt					1,948,081	1,974,209
Percent of capitalization					50.7%	47.6%
Total capitalization					$3,846,381	$4,148,857

*Redemption subject to certain restrictions regarding refunding operations.

See notes to financial statements.

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DUKE POWER COMPANY
STATEMENT OF SOURCE OF FUNDS FOR PLANT CONSTRUCTION COSTS
(Dollars in Thousands)

	Year Ended December 31				
	1974	1975	1976	1977	1978
Funds from operations					
Net income	$102,803	$117,143	$173,701	$192,349	$230,601
Non-fund items					
Depreciation and nuclear fuel amortization	96,846	110,327	118,646	134,048	170,373
Deferred income taxes and investment tax credit, net of amortization	42,936	50,802	107,019	85,347	89,786
Total equity component of the allowance for funds used during construction	-	-	-	(62,441)	(87,810)
Common equity component of the allowance for funds used during construction	(29,644)	(25,331)	(29,702)	-	-
Other, net	8,136	4,073	(1,259)	(4,766)	(2,669)
Funds from operations	221,077	257,014	368,405	344,537	400,281
Dividends paid on common stock	(59,263)	(70,949)	(87,833)	(103,755)	(121,961)
Dividends paid on preference and preferred stocks	(28,534)	(34,075)	(34,990)	(38,535)	(46,312)
Funds retained in the business	133,280	151,990	245,582	202,247	232,008
Funds from financing and sale of assets - net proceeds					
Sale of an interest in the Catawba Nuclear Station	-	-	-	-	260,047
First mortgage bonds	97,730	203,632	118,329	123,056	123,249
Pollution control obligations	-	-	2,364	-	80
Common stock	122,658	75,188	97,429	129,768	124,667
Preferred stock	-	57,450	-	99,874	89,674
Sale and sale/leaseback transactions	53,784	61,429	17,443	1,000	48,953
Term notes	116,982	-	-	-	-
Increase (decrease) in current notes payable	72,790	(57,049)	(59,043)	148,095	(174,095)
Retirement of long-term debt	(4,190)	(87,225)	(30,938)	(79,646)	(71,405)
Funds from financing and sale of assets	459,754	253,425	145,584	422,147	401,170
Total available funds	593,034	405,415	391,166	624,394	633,178
Working capital requirement (increase) decrease					
Materials and supplies	(61,460)	(44,670)	11,943	(22,739)	(29,549)
Investments in and advances to subsidiaries	(13,437)	(5,183)	13,414	5,352	14,006
Short-term U. S. government securities	-	-	-	-	(17,000)
Other, net	(37,029)	58,059	29,023	(24,833)	43,873
Net working capital requirement	(111,926)	8,206	54,380	(42,220)	11,330
Plant construction expenditures	481,108	413,621	445,546	582,174	644,508
Total equity component of the allowance for funds used during construction	-	-	-	62,441	87,810
Common equity component of the allowance for funds used during construction	29,644	25,331	29,702	-	-
Plant construction costs (including nuclear fuel)	$510,752	$438,952	$475,248	$644,615	$732,318

See notes to financial statements.

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DUKE POWER COMPANY
STATEMENT OF RETAINED EARNINGS
(Dollars in Thousands)

	Year Ended December 31				
	1974	1975	1976	1977	1978
BALANCE - Beginning of year	$101,386	$109,037	$114,521	$161,610	$207,897
ADD - Net income	102,803	117,143	173,701	192,349	230,601
Total	204,189	226,180	288,222	353,959	438,498
DEDUCT					
Dividends					
Common stock	59,263	70,949	87,833	103,755	121,961
Preference stock					
6 3/4% Convertible Series AA	3,375	3,375	3,375	3,375	3,184
Preferred stock (annual rates indicated)					
Series C ($4.50)	1,575	1,575	1,575	1,575	1,575
Series D ($5.72)	2,002	2,002	2,002	2,002	2,002
Series E ($6.72)	2,352	2,352	2,352	2,352	2,352
Series F ($8.70)	5,220	5,220	5,220	5,220	5,220
Series G ($8.20)	4,920	4,920	4,920	4,920	4,920
Series H ($7.80)	4,680	4,680	4,680	4,680	4,680
Series I ($7.35)	4,410	4,410	4,410	4,410	4,410
Series J ($8.20)	-	-	-	2,659	4,100
Series K ($8.28)	-	-	-	1,230	4,140
Series L ($8.375)	-	-	-	-	2,268
Series M ($8.84)	-	-	-	-	1,325
Preferred Stock A					
10.76%, 1975 Series	-	5,810	6,456	6,456	6,456
Capital stock expense	7,355	6,366	3,789	3,428	3,732
Total deductions	95,152	111,659	126,612	146,062	172,325
BALANCE - End of year	$109,037	$114,521	$161,610	$207,897	$266,173
Common dividends per share	$1.40	$1.40	$1.525	$1.63	$1.74

See notes to financial statements.

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DUKE POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Significant Accounting Policies

A. Additions to Electric Plant. The Company capitalizes all construction-related direct labor and materials as well as related indirect construction costs, including general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of repairs and replacements representing less than a unit of property is charged to electric expenses; the cost of renewals and betterments of units of property is capitalized. The original cost of property retired, together with removal costs less salvage, is charged to accumulated depreciation.

B. Allowance for Funds Used During Construction (ADC). ADC is an accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are transferred from the statement of income to construction work in progress in the balance sheet and, accordingly, are capitalized in the same manner as construction labor and material costs. This item is recognized as a cost of "Electric Plant," with offsetting credits to "Other Income" and "Interest Deductions," because under established regulatory rate practices, a utility is permitted to include a fair return on, and the recovery of, these capital costs through their inclusion in the rate base and in the provision for depreciation.

Effective January 1, 1977, the Federal Power Commission (now the Federal Energy Regulatory Commission) revised the Uniform System of Accounts to specify a formula for the determination of the maximum rate for computing ADC. The formula is based on embedded cost and permits compounding. This revision also prescribed the financial statement presentation of ADC which now consists of the "Allowance for equity funds used during construction" included in "Other Income" plus the "Allowance for borrowed funds used during construction" shown as a credit in "Interest Deductions." In conformity with such revision, the Company changed its presentation of ADC in the statement of source of funds for plant construction costs. The new formula for determining the amount of ADC did not have a significant impact on financial statements subsequent to 1976. The Company believes it would be inappropriate to reclassify the amounts of ADC for the periods prior to January 1, 1977 in the statement of income as this would imply that the prior periods were comparable when, in fact, prior to such date separate components were not required to be determined for the cost of borrowed funds and the cost of other funds.

The amount of ADC transferred in the five years ended December 31, 1978 has changed as the balance of construction work in progress has fluctuated and as interest rates and equity capital costs have increased. ADC has been calculated using current cost rates, net of applicable income taxes, of 7½% through June 30, 1974 and 8% from June 30, 1974 through December 31, 1976 and an average embedded rate of 6.92% for 1977 and 7.13% for 1978 calculated under the new formula with semi-annual compounding. If it is assumed that the principal funds used to finance construction during the three years ended December 31, 1976 were obtained 28% to 33% from common equity, 52% to 56% from debt at current costs net of income taxes and 13% to 15% from preference and preferred stocks at current costs, the common equity component of ADC as related to earnings for common stock would have amounted to 40%, 31% and 21% for 1974, 1975 and 1976, respectively. Earnings resulting from the common equity component of ADC are related principally to the additional capital obtained through the issuance of common stock.

C. Depreciation and Amortization. Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted average depreciation rates ranged from 3.25% to 3.28% during the five years ended December 31, 1978. Provisions for amortization of nuclear fuel, which are included in "Fuel used in electric generation," are recorded using the unit of production method. Nuclear fuel amortization includes an estimate of the net salvage value or removal costs. For fuel burned since July 1, 1977, a net removal charge has been included in such amortization in view of the present unavailability of reprocessing facilities. The estimated disposal costs for fuel burned prior to such date are being amortized currently over 10 years. All steam generator units, including nuclear, are depreciated at the rate of 3.57% (28 year life, net). The Company is continuing to evaluate the impact of nuclear plant decommissioning costs.

D. Income Taxes. The Company and its subsidiaries file a consolidated Federal income tax return. Income taxes are allocated to each company based on its taxable income or loss.

The Company's income taxes are allocated to electric operating expense and to non-electric operations under "Other Income." The "Income taxes - credit" classified under "Other Income" results from tax deductions of interest costs relating to investments in non-utility properties, mainly construction work in progress.

The Company provides deferred income taxes under normalization accounting for timing differences between book and tax income, principally resulting from accelerated tax depreciation, repair allowance, cost of removal, capitalized taxes and employee benefits and nuclear fuel disposal costs.

Investment tax credit (except for amounts applicable to the Employees' Stock Ownership Plan) is being deferred and amortized over the depreciable lives of the related properties. At December 31, 1978, the Company had unused investment tax credit amounting to approximately $67,421,000, of which $4,445,000 will be available for use through 1984 and the balance through 1985.

E. Retirement Plan Cost. The Company has a non-contributory retirement plan for the benefit of its employees. The Company's policy is to fund pension costs accrued, which amounted to $6,040,000 for 1974, $6,493,000 for 1975, $11,788,000 for 1976, $16,931,000 for 1977 and $20,053,000 for 1978.

The plan was amended, effective September 1, 1975, to provide increased participation and benefits. The total unfunded prior service costs of the plan amounted to approximately $20,489,000 in 1978 which generally are being amortized over 20 years.

The actuarially computed value of vested benefits under the plan exceeded the assets of the plan by $9,141,000 according to the latest available actuarial report.

F. Fuel Clause Revenues Accrued. Through December 31, 1978 the Company had procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. These procedures entail 60 to 90-day lags from the date changes in fuel expense occur until they are reflected in bills to customers. With respect to its South Carolina retail jurisdiction, the Company accrues revenues under such procedures in anticipation of recovering fuel expense in excess of that in base rates. Beginning in 1979, the procedures for North Carolina have been modified to limit the frequency at which the fuel cost factor in electric rates can be adjusted.

2. Rate Matters

Revenues reflect general rate increases granted to the Company during the past five years and adjustments under fuel clause procedures. See also Note 1F.

3. Subsidiaries

The Company has five active subsidiaries. Mill-Power Supply Company is a wholesale jobber and distributor of electrical supplies and equipment and acts as purchasing agent for the Company. Crescent Land & Timber Corp. is a land management and forestry company, whose principal holdings are non-utility land acquired from the Company. Eastover Mining Company mines coal for the Company (supplying 12% of its requirements for 1978) on properties owned or leased by Eastover Land Company, the Company's mineral holding subsidiary. Western Fuel, Inc. is involved in the exploration and development of uranium ore deposits.

The Company follows the equity method of accounting for such subsidiaries. Retained earnings include $19,179,000 of undistributed earnings of subsidiaries at December 31, 1978. Cash dividends received from subsidiaries were $1,600,000 in 1976, $850,000 in 1977 and $2,600,000 in 1978.

4. Earnings Per Share

Earnings per share of common stock are calculated by dividing earnings for common stock by the average number of common shares outstanding, which was 42,618,000 for 1974, 51,020,000 for 1975, 57,767,000 for 1976, 63,630,000 for 1977 and 70,367,000 for 1978. Conversion of the Preference Stock, 6 3/4% Convertible Series AA, would not have a material dilutive effect. See Exhibit 1 for calculation of fully diluted earnings per share.

5. Long-Term Debt

First and refunding mortgage bonds outstanding at December 31, 1977 and 1978 were as follows (dollars in thousands):

Series	Year Due	1977	1978	Series (Continued)	Year Due	1977	1978
2 7/8%	1979	$ 40,000	$ 40,000	7 1/2%	2001	$ 100,000	$ 100,000
3 1/4%	1981	35,000	35,000	7 3/8% B	2001	40,000	40,000
3 5/8%	1986	30,000	30,000	7 3/4%	2002	100,000	100,000
4 1/2%	1992	50,000	50,000	7 3/8% B	2002	75,000	75,000
4 1/4% B	1992	50,000	50,000	7 3/4%	2003	100,000	100,000
4 1/2%	1995	40,000	40,000	8 1/8% B	2003	100,000	100,000
5 3/8%	1997	75,000	75,000	9 3/4%	2004	100,000	100,000
6 3/8%	1998	75,000	75,000	9 1/2%	2005	100,000	100,000
7%	1999	75,000	75,000	11%	1994	118,250	111,500
8% B	1999	75,000	75,000	8 3/8%	2006	100,000	100,000
8 1/2%	2000	75,000	75,000	8 1/8%	2007	125,000	125,000
8 5/8% B	2000	100,000	100,000	9 3/8%	2008	-	125,000
						$1,778,250	$1,896,500

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Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds which does not specify any authorized amount of Bonds, issuance being limited by property additions, earnings and other provisions of such Indenture. The Indentures relating to the 4 7/8% Sinking Fund Debentures due September 1, 1982 and 13% Notes due September 1, 1979 limit such issues to their presently outstanding principal amounts.

The sinking fund provisions of the First and Refunding Mortgage Bonds, 11% Series Due 1994, require the annual retirement of $6,750,000 of such Bonds beginning July 1, 1977, and the sinking fund provisions of the 4 7/8% Sinking Fund Debentures require the annual retirement of $1,250,000 principal amount of such Debentures.

The annual amounts of long-term debt maturities (including sinking fund requirements and capitalized lease principal payments) through 1983 are $149,080,000 in 1979, $9,103,000 in 1980, $44,129,000 in 1981, $32,906,000 in 1982 and $9,589,000 in 1983.

6. Capital Stock and Retained Earnings

The preference and preferred stocks are callable, in whole or in part, at redemption prices which decline over a period of years within the limits shown in the Statement of Capitalization, plus dividends accrued to the redemption date.

The 7.35% Preferred Stock, Series I, provides for a sinking fund for the annual redemption of 24,000 shares at $100 per share on a cumulative basis beginning March 16, 1984. The Company may at its option, on a non-cumulative basis, redeem an additional 24,000 shares annually at $100 per share beginning March 16, 1984; such redemption option is limited to an aggregate of 200,000 shares.

The 8.20% Preferred Stock, Series J, provides for a sinking fund for the annual redemption of 20,000 shares at $100 per share on a cumulative basis beginning June 16, 1982. The Company may at its option, on a non-cumulative basis, redeem an additional 20,000 shares annually at $100 per share beginning June 16, 1982; such redemption option is limited to an aggregate of 175,000 shares.

The 8.375% Preferred Stock, Series L, provides for a sinking fund for the annual redemption of 20,000 shares at $100 per share on a cumulative basis beginning June 16, 1983. The Company may at its option, on a non-cumulative basis, redeem an additional 20,000 shares annually at $100 per share beginning June 16, 1983; such redemption option is limited to an aggregate of 166,666 shares.

The 10.76% Preferred Stock A, 1975 Series, provides for a sinking fund for the annual redemption of 60,000 shares at $25 per share on a cumulative basis beginning March 16, 1980. The Company may at its option, on a non-cumulative basis, redeem an additional 60,000 shares annually at $25 per share beginning March 16, 1980.

The outstanding Preference Stock, 6 3/4% Convertible Series AA, is convertible into shares of common stock at the adjusted conversion price of $24.73 per share at December 31, 1978, each share of such Preference Stock being taken at $100 for such purposes. The conversion price is subject to certain adjustments designed to protect the conversion privilege against dilution. In 1978, 75,383 shares were converted into 304,108 shares of common stock.

Certain shares of common stock were reserved for issuance at December 31, 1978 as follows:

Conversion of the Preference Stock, 6 3/4% Convertible Series AA	1,716,405
Stock Purchase-Savings Program for Employees	914,111
Dividend Reinvestment and Stock Purchase Plan	953,679
Employees' Stock Ownership Plan	961,408
Total	4,545,603

In 1976 the Company adopted an Employees' Stock Ownership Plan for taxable years 1975 and 1976 and reserved 300,000 shares of its common stock for issuance under such Plan. The shareholders adopted a proposal in 1978 to modify and continue the Plan and to reserve an additional 850,000 shares for use thereunder in subsequent years. The Plan, as modified, will be funded by additional investment tax credit and employee contributions.

Issues of shares of capital stock for the five years ended December 31, 1978 were as follows:

	Year Ended December 31				
	1974	1975	1976	1977	1978
Common:					
Public sales	8,500,000	5,000,000	5,000,000	5,500,000	5,500,000
Stock Purchase-Savings Program for Employees	407,884	504,241	418,563	443,471	623,141
Dividend Reinvestment and Stock Purchase Plan	177,503	180,968	179,807	191,781	260,912
Employees' Stock Ownership Plan	-	-	59,864	114,632	14,096
Conversion of Preference Stock	-	-	-	586	304,108
Total common	9,085,387	5,685,209	5,658,234	6,250,470	6,702,257
Preferred:					
Public sales					
$100 par	-	-	-	500,000	400,000
$25 par	-	2,400,000	-	-	-
Private placements					
$100 par	-	-	-	500,000	500,000

The Indentures relating to the 4 7/8% Sinking Fund Debentures due September 1, 1982, and 13% Notes due September 1, 1979 provide, among other things, for certain restrictions on the payment of cash dividends. Under the terms of such Indentures, none of the Company's retained earnings as of December 31, 1978 was restricted with respect to the declaration or payment of dividends.

7. Leases

Rentals incurred during the five-year period 1974-1978 and rental commitments at December 31, 1978 under financing leases not capitalized and operating leases were as follows (dollars in thousands):

	Financing Leases Not Capitalized	Operating Leases	Total
Rentals Incurred:			
1974	$11,775	$ 2,230	$ 14,005
1975	36,003	2,060	38,063
1976	36,009	1,534	37,543
1977	29,912	1,912	31,824
1978	21,786	2,015	23,801
Rental Commitments:			
1979	12,565	2,269	14,834
1980	12,485	2,107	14,592
1981	12,331	2,294	14,625
1982	12,127	2,539	14,666
1983	11,882	2,814	14,696
Later years	91,309	16,167	107,476

Rentals charged to operating expenses were $11,765,000 in 1974, $34,593,000 in 1975, $34,629,000 in 1976, $29,248,000 in 1977 and $21,098,000 in 1978.

Substantially all leases require the Company to pay taxes and operation and maintenance expenses. Rentals incurred and rental commitments under combustion turbine generator leases include accruals in excess of current payments in amounts required to equalize annual rent expense and satisfy the obligations of the lease, net of salvage, at the end of the estimated useful life of the generators. Such leases contain options to purchase beginning in 1981 at the lessors' unrecovered cost. Rentals under nuclear fuel leases are based on usage. Other leases generally contain options to purchase at the lessor's unrecovered cost or fair market value.

Obligations under capitalized leases are included in long-term debt. Had the Company capitalized its remaining financing leases, the original cost of "Electric plant in service" and "Long-term debt" would have increased as follows (dollars in thousands):

	1977	1978
Electric plant in service	$158,100	$114,800
Capitalized leases	$ 79,800	$ 66,200
Less current maturities	8,700	1,500
Long-term debt	$ 71,100	$ 64,700

The effect of such capitalization on expenses would not have been material for any of the five years ended December 31, 1978.

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8. Income Tax Expense

Income tax expense consisted of the following:

	Year Ended December 31				
	1974	1975	1976	1977	1978
	(Dollars in Thousands)				
Electric Expenses					
Current income taxes					
Federal	$10,905	$36,361	$ 25,927	$ 37,122	$ 42,187
State	1,539	5,379	10,978	9,278	11,279
	12,444*	41,740*	36,905*	46,400*	53,466*
Deferred taxes, net**					
Excess tax over book depreciation	38,459	42,756	41,443	38,127	33,770
Repair allowance and cost of removal	5,426	4,091	4,699	7,434	6,153
Capitalized taxes, employee benefits, etc.	-	4,361	9,482	12,465	13,720
Nuclear fuel disposal costs	-	-	-	-	(9,610)
	43,885	51,208	55,624	58,026	44,033
Investment tax credit					
Deferred	-	-	53,372	28,949	45,467
Amortization of deferments (credit)	(949)	(406)	(1,977)	(1,618)	(2,540)
	(949)	(406)	51,395	27,331	42,927
Total electric expenses	55,380	92,542	143,924	131,757	140,426
Other Income					
Income taxes-other, net	4,614	(930)	(640)	(778)	16,963
Income taxes-credit					
Federal	(18,277)	(18,411)	(19,703)	(22,518)	(31,532)
State	(2,431)	(2,448)	(2,620)	(2,995)	(4,193)
Total other income	(16,094)*	(21,789)*	(22,963)*	(26,291)*	(18,762)*
Total income tax expense	$39,286	$70,753	$120,961	$105,466	$121,664

*Net taxes payable (refundable) amounted to ($3,650,000), $19,951,000, $13,942,000, $20,109,000 and $34,704,000 for 1974, 1975, 1976, 1977 and 1978, respectively. However, for consolidated income tax purposes, only a minimum amount of income taxes may be payable currently due to utilization of tax loss and investment tax credit carryovers of the Company and certain subsidiaries.

**"Deferred taxes, net" included state income taxes of $5,151,000 for 1974, $5,511,000 for 1975, $6,406,000 for 1976, $6,489,000 for 1977 and $4,521,000 for 1978.

Income taxes differed from amounts computed by applying the statutory tax rate to pretax income as follows (dollars in thousands):

	Year Ended December 31				
	1974	1975	1976	1977	1978
Income taxes on pretax income at the statutory Federal rate of 48%	$68,203	$90,190	$141,438	$142,951	$169,087
Increase (reduction) in tax resulting from:					
Allowance for all funds used during construction (ADC)	(29,836)	(26,301)	(29,628)	(41,681)	(58,546)
Pensions and taxes capitalized on books	(4,884)	(2,797)	-	-	-
Amortization of investment tax credit deferrals	(949)	(406)	(1,977)	(1,618)	(2,540)
Amortization of nuclear fuel book-tax basis difference (principally ADC)	-	1,845	1,568	1,382	1,363
Excess of tax gain over book profit on sale of assets (principally ADC)	-	-	-	-	5,647
State income taxes, net of Federal income tax benefit	2,520	4,333	7,638	6,595	7,801
Other items, net	4,232	3,889	1,922	(2,163)	(1,148)
Total income tax expense (see above)	$39,286	$70,753	$120,961	$105,466	$121,664

9. Short-Term Borrowings

The Company has lines of credit with 80 commercial banks and uses these lines, plus the sale of commercial paper, to finance its current cash requirements. Bank loans are for 90 days or less.

At December 31, 1977 and December 31, 1978, $202,590,000 and $222,500,000 of the Company's bank lines of credit required compensating balances of approximately $18,068,000 and $20,087,000, respectively. The remaining lines of credit (principally non-daily depository accounts) were on a fee basis calculated in general to equate to the value of balances. Borrowings are principally at the lending bank's commercial prime interest rate. Certain of the Company's bank line arrangements may require additional balances equal to 10% of the borrowings on an annual average.

A summary of information relating to short-term borrowings is as follows (dollars in thousands):

	1977	1978
Amount outstanding at year end		
Bank loans - 7.75%	$ 16,000	-
Commercial paper - average rate of 6.74%	$158,095	-
Maximum amount outstanding during the year	$174,095	$175,295
Average amount outstanding during the year	$ 37,812	$ 61,695
Lines of credit at year end	$260,090	$280,000
Weighted average interest rate for the year - computed on a daily basis	6.43%	7.68%

10. Other Income

In November, 1978, the Company sold a 75% interest in Unit No. 2, scheduled for commercial operation in 1983, of the Catawba Nuclear Station and 37½% of its support facilities to the North Carolina Municipal Power Agency Number 1, representing certain North Carolina municipal customers. A net of tax profit of approximately $11,242,000 from the sale has been included in "Other Income". Income taxes of $24,927,000 related to the transaction reflect a taxable gain in excess of book gain resulting principally from the treatment of ADC. At December 31, 1978, "Construction work in progress" included $413,623,000, representing the Company's investment in its remaining interest in the Catawba Nuclear Station. Progress payments will be made monthly by the North Carolina Municipal Power Agency Number 1 as additional costs are incurred for construction.

In addition, the Company has recorded a charge of approximately $10,068,000 (after giving effect to income taxes of $9,297,000) to reflect a reduction in the carrying value of investments that have been made pursuant to the terms of a certain coal supply contract.

In 1974 and 1975 the Company disposed of certain assets to augment its source of funds. Gains and losses on such transactions were included in "Other, net (deduction)".

11. Commitments and Contingencies

The Company is engaged in a long-range construction program for which substantial commitments have been made. (See "Item 1 Business - CONSTRUCTION PROGRAM").

The Company's public liability for claims resulting from nuclear incidents is limited to $560 million under provisions of the Price-Anderson Act which also provides for supplemental nuclear liability insurance up to that amount. Under Nuclear Regulatory Commission regulations effective August 1, 1977, the Company could be assessed up to $5 million for each of its licensed reactors in connection with a nuclear incident involving any licensed facility in the nation and up to $10 million a year for each of its licensed reactors in the event of more than one incident. The Company has three licensed reactors.

Property damage coverage for certain of the Company's nuclear facilities is provided through membership in Nuclear Mutual Limited (NML). If NML's losses were to exceed its reserves, the Company would be liable for additional assessments of up to approximately $32,000,000, representing 14 times the Company's current annual premium to NML.

12. Supplementary Earnings Statement Information

In addition to the amounts of maintenance (including repairs) and provisions for depreciation of electric plant which are shown separately in the Statement of Earnings, other amounts, which are not significant, are charged to "Other Income-Other, net (deduction)" and to clearing and other accounts.

Research and development costs and advertising costs were each less than 1% of total revenues for each of the years reported. No royalties were paid.

The following tabulation sets forth, for the years indicated, provisions for general taxes (dollars in thousands):

	Year Ended December 31				
	1974	1975	1976	1977	1978
Real and personal property	$23,058	$28,416	$30,345	$ 32,664	$ 34,917
State and city franchise	35,816	40,682	48,375	54,884	61,140
Other	13,853	13,721	15,451	18,561	22,939
Total	$72,727	$82,819	$94,171	$106,109	$118,996
Charged to					
Electric expenses	$64,710	$75,757	$85,215	$ 95,309	$103,816
Construction	7,402	6,424	8,258	10,061	14,410
Other income	615	638	698	739	770
Total	$72,727	$82,819	$94,171	$106,109	$118,996

13. Replacement Cost (Unaudited)

The estimated replacement cost of the Company's electric system (productive capacity) is presented below in compliance with the disclosure requirements of the Securities and Exchange Commission. This information does not purport to represent the current value of the existing electric plant in service; it is only an estimate of the cost that would be incurred if such assets were replaced at December 31, 1977 and 1978 (dollars in thousands).

	December 31, 1977		December 31, 1978	
	Estimated Replacement Cost	Historical Cost	Estimated Replacement Cost	Historical Cost
Electric plant in service	$8,084,000	$3,761,353	$8,787,233	$3,964,825
Less accumulated depreciation and amortization	2,322,000	1,068,103	2,754,663	1,239,250
Electric plant in service, net	$5,762,000	$2,693,250	$6,032,570	$2,725,575

The amount of depreciation charged to expense was $115 million for 1977 and $119 million for 1978. The annual depreciation computed on the basis of estimated replacement cost would be $249 million for 1977 and $267 million for 1978.

Land and land rights and nuclear fuel are included in the replacement cost data above at their historical cost of $248 million for 1977 and $304 million for 1978. The replacement cost of thermo-generation facilities was determined by applying the Company's estimates of current construction costs (which reflect current environmental and regulatory requirements) for each type of thermo-generation to the actual capacity at year end. The replacement cost of the remaining plant in service, including hydro-generation facilities, was determined by applying trending indices prepared specifically for the Company to the surviving plant by vintage.

The related accumulated depreciation based on replacement cost was developed by applying the ratio between gross plant accumulated depreciation for each functional group (production, transmission, distribution and general facilities) on a historical cost basis to the estimated replacement cost of such group. Annual replacement cost depreciation was computed by applying the current book accrual rates for each functional group to its average replacement cost for 1977 and 1978.

Replacement cost has not been estimated for nuclear fuel because amortization of the cost is included in fuel expense and recognized through fuel cost adjustment procedures.

The difference between historical and estimated replacement cost of the net electric plant in service does not represent an unrecorded increment in the common shareholders' equity; rather it represents a theoretical additional capital investment which would be required if the electric plant in service were replaced in its entirety at December 31, 1977 and 1978. It is anticipated that, as the replacement cost of facilities is incurred in the future, electric rates will reflect, under present regulatory procedures, the higher depreciation expense associated with such investments.

14. Selected Quarterly Information (Unaudited)

A summary of quarterly financial data for 1977 and 1978 is as follows (dollars in thousands except per share figures):

Quarter Ended	Electric Revenues	Electric Operating Income	Net Income	Earnings Per Share of Common Stock
March 31, 1977	$328,750	$73,905	$61,040	$0.88
June 30, 1977	278,113	50,140	40,062	0.46
September 30, 1977	329,948	47,559	40,854	0.47
December 31, 1977	330,163	58,282	50,393	0.60
March 31, 1978	371,003	74,775	69,194	0.87
June 30, 1978	309,548	49,379	48,034	0.52
September 30, 1978	362,826	52,984	52,455	0.55
December 31, 1978	353,343	59,863	60,918	0.67

Quarterly earnings generally fluctuate with seasonal weather conditions. In both 1977 and 1978, quarterly earnings also were affected by varying fuel expense resulting from changes in generation mix. Nuclear generation decreased and fossil-fueled generation increased during periods of refueling and nuclear plant maintenance. Quarterly earnings were affected further by the lag inherent in revenue billing procedures applicable to fuel expense. The fourth quarter of 1978 also reflects increases implemented on September 1, 1978 in the Company's electric rate schedules.

DUKE POWER COMPANY
SCHEDULE V - PROPERTY, PLANT AND EQUIPMENT
FOR THE YEARS ENDED DECEMBER 31, 1977 AND 1978
(Dollars in Thousands)

Description	Balance Beginning Of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1977					
Electric Plant in Service - At Original Cost					
Production	$1,799,149	$ 20,986	$ 352	$ 53	$1,819,836
Transmission	669,063	29,719	1,659	1,741	698,864
Distribution	965,509	71,397	6,921	2,808	1,032,793
General	83,428	18,521	1,831	226	100,344
Miscellaneous	2,843	7,368	-	-	10,211
Nuclear fuel	56,662	42,643	-	-	99,305
Total electric plant in service	3,576,654	190,634	10,763	4,828	3,761,353
Construction Work in Progress	1,083,716	454,805	-	-	1,538,521
Other Property - At Cost					
Water plant	16,633	53	2	7	16,691
Transit plant	525	-	-	-	525
Non-utility plant	9,594	(877)	12	-	8,705
Total other property	26,752	(824)	14	7	25,921
Total plant	$4,687,122	$644,615	$10,777	$ 4,835*	$5,325,795
For the Year Ended December 31, 1978					
Electric Plant in Service - At Original Cost					
Production	$1,819,836	$ 10,556	$ 842	$ 17	$1,829,567
Transmission	698,864	39,269	3,007	(546)	734,580
Distribution	1,032,793	67,737	8,163	4,397	1,096,764
General	100,344	34,337	976	12,191	145,896
Miscellaneous	10,211	(10)	-	-	10,201
Nuclear fuel	99,305	48,512	-	-	147,817
Total electric plant in service	3,761,353	200,401	12,988	16,059*	3,964,825
Construction Work in Progress	1,538,521	531,340	-	(225,538)**	1,844,323
Other Property - At Cost					
Water plant	16,691	798	1	(15)	17,473
Transit plant	525	-	-	-	525
Non-utility plant	8,705	(221)	20	(4)	8,460
Total other property	25,921	577	21	(19)*	26,458
Total plant	$5,325,795	$732,318	$13,009	$(209,498)	$5,835,606

*Principally due to salvage credit, retirement cost, and adjustments for prior years.

**Represents the book value of an asset (the Catawba Nuclear Station) sold in November 1978.

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DUKE POWER COMPANY

SCHEDULE VI - ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
FOR THE YEARS ENDED DECEMBER 31, 1977 AND 1978
(Dollars in Thousands)

Description	Beginning Of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1977						
Accumulated Depreciation of Electric Plant						
Production	$ 447,202	$ 58,368	$ -	$ 493	$ -	$ 505,077
Transmission	155,328	19,221	-	377	77	174,249
Distribution	284,113	33,822	-	4,715	1,572	314,792
General	27,853	3,563	1,329	1,743	136	31,138
Miscellaneous	624	-	491	-	-	1,115
	915,120	114,974	1,820	7,328	1,785	1,026,371
Accumulated Amortization of Nuclear Fuel	24,842	-	16,890	-	-	41,732
	939,962	114,974	18,710	7,328	1,785	1,068,103
Accumulated Depreciation of Water Plant	4,034	328	-	1	-	4,361
Accumulated Depreciation of Transit Plant	75	37	-	-	-	112
Total Accumulated Depreciation	$ 944,071	$115,339	$18,710	$7,329	$ 1,785	$1,072,576
For the Year Ended December 31, 1978						
Accumulated Depreciation of Electric Plant						
Production	$ 505,077	$ 58,876	$ -	$ 826	$ -	$ 563,127
Transmission	174,249	20,218	-	3,303	(249)	190,915
Distribution	314,792	36,100	-	4,605	838	347,125
General	31,138	3,726	2,370	682	11,883	48,435
Miscellaneous	1,115	-	491	-	-	1,606
	1,026,371	118,920	2,861	9,416	12,472	1,151,208
Accumulated Amortization of Nuclear Fuel	41,732	-	46,310	-	-	88,042
	1,068,103	118,920	49,171	9,416	12,472	1,239,250
Accumulated Depreciation of Water Plant	4,361	325	-	1	-	4,685
Accumulated Depreciation of Transit Plant	112	38	-	-	-	150
Total Accumulated Depreciation	$1,072,576	$119,283	$49,171	$9,417	$12,472	$1,244,085

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DUKE POWER COMPANY
SCHEDULE XII - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE YEARS ENDED DECEMBER 31, 1977 AND 1978
(Dollars in Thousands)

Description	Balance Beginning Of Year	Charged To Costs and Expenses	Deductions	Balance End Of Year
For the Year Ended December 31, 1977				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$2,369	$4,614	$3,930 (1)	$3,053
Other Reserves				
Operating Reserves (3)	$4,015	$1,659	$ 798 (2)	$4,876
For the Year Ended December 31, 1978				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$3,053	$3,903	$3,348 (1)	$3,608
Other Reserves				
Operating Reserves (3)	$4,876	$3,896	$1,168 (2)	$7,604

(1) Uncollectible accounts written off, net of recoveries.

(2) Entries represent payments for injuries and damages in North and South Carolina.

(3) Consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits," on the Balance Sheet.

[redacted]

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE

(Dollars in Thousands)

This calculation is submitted in accordance with Securities Exchange Act of 1934 Release No. 9083 although not required by footnote 2 to paragraph 14 of APB Opinion No. 15 because it results in dilution of less than 3%.

	Year Ended December 31				
	1974	1975	1976	1977	1978
Fully Diluted:					
Earnings applicable to common stock (A)	$74,269	$82,799	$138,711	$153,470	$183,969
Add: Preference Stock Dividends, Convertible 6 3/4% AA, $100 par, 500,000 shares (424,467 shares in 1978) outstanding as of December 31	3,375	3,375	3,375	3,375	3,184
Earnings as adjusted for computation	$77,644	$86,174	$142,086	$156,845	$187,153
Average common shares outstanding - Twelve months (000)	42,618	51,020	57,767	63,630	70,367
Add: Common shares required for conversion of Preference Stock, Convertible 6 3/4% AA, $100 par, 500,000 shares (424,467 shares in 1978) outstanding as of December 31 (B)	1,803	1,898	1,956	1,956	1,716
Common shares as adjusted for computation	44,421	52,918	59,723	65,586	72,083
Fully diluted earnings per share	$1.75	$1.63	$2.38	$2.39	$2.60

(A) These figures agree with the related amounts in the Summary of Operations.

(B) The conversion price used to convert the Preference Stock, 6 3/4% Convertible Series AA into shares of common stock is $27.73, $26.35, $25.56, $25.56 and $24.73 for 1974, 1975, 1976, 1977 and 1978, respectively.

EXHIBIT I

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SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1979 Commission File Number: 1-4928

Duke Power Company

(Exact name of registrant as specified in its charter)

North Carolina	56-0205520
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
422 South Church Street Charlotte, North Carolina	28242
(Address of principal executive offices)	(Zip Code)

704-373-4573

(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
Preference Stock, par value $100	
6¼% Convertible Series AA	New York Stock Exchange
Preferred Stock, par value $100	
8.70% Series F	New York Stock Exchange
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
8.84% Series M	New York Stock Exchange
8.84% Series N	New York Stock Exchange
Preferred Stock A, par value $25	
10.76% Series 1975	New York Stock Exchange
First and Refunding Mortgage Bonds	
7⅛% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7⅛% Series B Due 2002	New York Stock Exchange
7¾% Series Due 2003	New York Stock Exchange
8⅛% Series B Due 2003	New York Stock Exchange
9¼% Series Due 2004	New York Stock Exchange
9½% Series Due 2005	New York Stock Exchange
8⅜% Series Due 2006	New York Stock Exchange
8⅛% Series Due 2007	New York Stock Exchange
9⅜% Series Due 2008	New York Stock Exchange
10⅛% Series Due 2009	New York Stock Exchange
10⅛% Series B Due 2009	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class
Preferred Stock, par value $100

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the close of the period covered by this report.

Title of Class	Outstanding at December 31, 1979
Common Stock without par value	79,488,939

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PART I

Item 1. *Business.*

DUKE POWER COMPANY

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,000,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1979 the Company's electric revenues amounted to approximately $1.5 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks ninth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242.

Factors Affecting the Industry. The electric utility industry in general has been experiencing problems in a number of areas including the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities, particularly in the aftermath of the Three Mile Island accident; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; difficulty in obtaining sufficient capital on reasonable terms; difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

For a discussion of the developments affecting the Company, see "Construction Program" (pages 2 through 6), "Business—Rate Matters" (pages 8 and 9), "Business—Fuel Supply" (pages 9 through 12), "Business—Regulation—*Environmental Matters*" (pages 12 through 14) and "Business—Regulation—*Nuclear Facilities*", which contains, among other things, information concerning possible delay in the granting of an operating license for the McGuire Nuclear Station and the current implementation of various requirements of the Nuclear Regulatory Commission with respect to the operation of the Oconee Nuclear Station (pages 14 and 15).

FINANCING PROGRAM

The Company presently estimates that it will obtain through the sale of securities and other external sources between 50% and 55% of its 1980-1982 total capital requirements, which include cost estimates of $2.1 billion for the construction program, $583 million for nuclear fuel, $95 million for the refunding of maturing long-term debt and sinking fund requirements and approximately $125 million related to maturities with respect to capitalized nuclear fuel trusts. The balance of such requirements is expected to be obtained from retained earnings, depreciation and amortization, deferred taxes, investment tax credit and other internal sources. Such expectation is based in part upon receiving future rate increases as to which no assurance can be given. On February 14, 1980, the Company received proceeds of approximately $49.4 million from the sale of 500,000 shares of 11% Cumulative Preferred Stock, Series O (par value $100) (the New Preferred Stock). In addition, on March 19, 1980, the Company received proceeds of approximately $148 million from the sale of $100,000,000 principal amount of First and Refunding Mortgage Bonds, 14¼% Series Due 2010, and $50,000,000 principal amount of First and Refunding Mortgage Bonds, 14⅛% Series Due 1987 (collectively, the New Bonds). The types, amounts and timing of sales of additional securities will depend upon market conditions and other factors.

The foregoing estimates of the Company's capital requirements expected to be obtained from external sources assume no sale of any portion of the Company's remaining interest in the Catawba Nuclear Station. As described under "Construction Program—Facilities Under Construction", the Company has agreed in principle to sell to a group of its South Carolina municipal customers, and is negotiating to sell to a group of its cooperative customers, portions of its remaining interest in that Station. The Company has no assurance that either sale will be completed. However, consummation of either sale would reduce the amount of external financing required by the Company by the amount initially received and by the amounts of progress payments to be made as additional construction costs are incurred. If the sale to the South Carolina municipal customers is consummated by the end of 1980, the Company anticipates that it will receive approximately $200 million at that time.

In order to issue additional mortgage bonds and preferred stock, the Company must comply with earnings coverage and assets requirements contained in its mortgage indenture and articles of incorporation. Under the provisions of such indenture, additional bonds (other than certain types of refunding bonds) may not be issued unless the Company's available net earnings (as defined) for 12 consecutive calendar months within the 15 calendar months immediately preceding shall have been at least twice the amount of the annual interest charges on all bonds outstanding and applied for under the indenture. Additional bonds may be issued only against cash, certain retired bonds and 66⅔% of the aggregate of the net amounts of additional property certified to the trustee pursuant to the indenture.

Under its articles of incorporation, the Company may not issue additional shares of preferred stock unless, after giving effect thereto, (i) its net earnings available for dividends on the preferred stock for any 12 consecutive calendar months within the 15 calendar months preceding the month in which the additional shares are to be issued shall have been at least twice the dividend requirements for a 12-month period upon the entire amount of preferred stock and all other stock ranking prior to or on a parity with the preferred stock, and (ii) the total net assets of the Company at a date not more than 90 days prior to the date on which the additional shares are to be issued shall equal at least twice the aggregate amount payable upon the involuntary liquidation of the Company to the holders of the preferred stock and all other stock ranking prior to or on a parity with the preferred stock.

On the basis of these requirements, the Company's interest and dividend coverages for the years shown were as follows:

	Year Ended December 31				
	1975	1976	1977	1978	1979
Mortgage bond interest	3.07	3.74	3.60	3.47	3.11
Preferred stock dividends	3.71	5.49	4.83	4.85	5.28

The pro forma interest and dividend coverages were 2.76 and 4.78, respectively, for 1979 after giving effect to the issuance and sale of the New Preferred Stock and the New Bonds.

As of December 31, 1979, the Company could have issued approximately $520 million of preferred stock based upon the amount of net assets of the Company available upon liquidation as provided in its articles of incorporation, after giving effect to the issuance of the New Preferred Stock. As of such date, after giving effect to the issuance of the New Bonds, the Company could have issued under the earnings test approximately $510 million principal amount of bonds, assuming utilization of the Company's construction work in progress, the major portion of which is nuclear, as property additions under the mortgage indenture.

CONSTRUCTION PROGRAM

Estimated Costs

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rate increases), the availability and cost of capital in the financial markets, the

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availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise (see "Opposition to Nuclear Power Development") and changing regulatory and environmental standards (see "Business—Regulation—*Environmental Matters*"). The estimates of construction costs and the timing of construction expenditures are also subject to the sale of a portion of the Company's remaining interest in the Catawba Nuclear Station. The Company is keeping its construction program as flexible as possible in order to accommodate any variations as a result of such considerations.

Costs for the construction program, including the acquisition of nuclear fuel, for each of 1980, 1981 and 1982 and for the three-year period 1980-1982, as now scheduled, are currently estimated, assuming no sale of any portion of the Company's remaining interest in the Catawba Nuclear Station, as follows (in millions of dollars):

Type of Facilities	1980	1981	1982	1980-1982
Generation	$593	$477	$397	$1,467*
Transmission	60	48	48	156
Distribution	97	103	119	319
Other	27	31	63	121
Total	$777**	$659**	$627**	$2,063**
Nuclear Fuel	$100	$241	$242	$ 583

* Cost estimates for the three-year period 1980-1982 include approximately $100 million attributable to the portion of the Catawba Nuclear Station which the Company has agreed in principle to sell to a group of its South Carolina municipal customers and approximately $280 million attributable to the portion that it is currently negotiating to sell to a group of its cooperative customers (see "Facilities Under Construction"). Such estimates do not include expenditures of as much as $224 million which may be required to achieve consistent compliance with maximum particulate emission limitations in the event that the modification of the standards authorized by the North Carolina Environmental Management Commission is not approved by the United States Environmental Protection Agency (see "Business—Regulation—*Environmental Matters*").

** The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, and allowances for inflation utilizing Bureau of Labor Statistics indices. Effect has also been given to a North Carolina statute requiring, for ratemaking purposes, the inclusion in the rate base of construction expenditures incurred after July 1, 1979 and requested in rate applications filed on or after such date, which will result in lower capital costs due to a corresponding reduction in the allowance for funds used during construction (see "Business—Rate Matters").

The Company is continuing to experience increases in the cost of construction of new facilities as a result of recurring rises in the costs of materials, labor and capital, and increasing capital requirements for environmental purposes.

The construction program, as now scheduled, reflects a recent decision to defer by three years the operating dates of the two units of the Cherokee Nuclear Station currently under construction (see "Facilities Under Construction") because of inflationary pressures, sharply increased construction costs and the Company's continuing inability to earn the rates of return allowed in its three regulatory jurisdictions, the latter being a factor in the Company's Common Stock selling below its book value (see "Business—Rate Matters"). Although such deferral will result in near-term reductions in expenditures that otherwise would be required, as have deferrals in prior years, cost escalations and general inflationary price trends will, over the long term, increase construction costs per KW.

The Company currently is engaged in a comprehensive load management program designed to reduce the growth in peak demand without restricting the continued economic development of the Company's service area. Such program includes, among other things, promotion of energy-efficient building structures and appliances, use of residential conservation rates, use of interruptible rates for large customers, control by the Company (with customers' consent) of residential electric water heaters and air conditioners during

peak demand periods and time-of-day pricing on an experimental basis to a limited number of customers. The current and planned aspects of such program are designed to reduce the growth in peak demand by approximately 2,410,000 KW in the summer of 1989 and 3,513,000 KW in the summer of 1994 (from estimated peak demands at those times without load management) and to enhance generating reserve margins through the ability to interrupt approximately 687,000 KW of load in 1989 and 995,000 KW in 1994. The Company has premised its current construction program on such load management program which the Company believes has resulted in a current estimated accumulated reduction of approximately 424,000 KW in its summer peak load and approximately 551,000 KW in its winter peak load. (For information about the Company's peak loads, see "Business—Energy Requirements and Capability".)

The Company estimates a minimum reserve margin of approximately 22% above its anticipated peak load requirements through 1982. Based on the Company's current growth projections, its current and planned load management program, taking into consideration the availability of interruptible loads, and the recently revised construction program, it is anticipated that the minimum reserve margin would decrease to approximately 9% in 1989. The Company will continue to seek additional load management results but also has the option of accelerating the scheduled completion of the Bad Creek Hydroelectric Station to improve the reserve margin at that time (see "Planned Facilities").

During the five-year period 1975-1979, gross property additions (including nuclear fuel) and net retirements amounted to approximately $3.1 billion and $293 million, respectively, resulting in a net increase of approximately $2.8 billion, or 74%, in gross plant. Net retirements include the interest in the Catawba Nuclear Station sold to the North Carolina Municipal Power Agency Number 1 (see "Facilities Under Construction").

Facilities Under Construction

The following table sets forth the major generating facilities of the Company currently under construction which are to be added to its present generating capability of 12,048,000 KW:

Unit and Location	Net KW Capability	Energy Source	Company Ownership (%)	Date of Planned Operation(1)	Estimated Construction Cost per KW(2)	Total Estimated Construction Costs(2)	Amounts Expended Through December 31, 1979(2)
						(Dollars in Millions)	
McGuire No. 1	1,180,000	Nuclear	100	Late 1980	$ 648	$1,500	$1,133
McGuire No. 2	1,180,000	Nuclear	100	1982			
(Northwest of Charlotte, in North Carolina)							
Catawba No. 1	1,145,000	Nuclear	100	1983	903	1,300(3)	586(3)
Catawba No. 2	1,145,000	Nuclear	25	1985			
(Southwest of Charlotte, in South Carolina)							
Cherokee No. 1	1,280,000	Nuclear	100	1990	1,779	4,500	277
Cherokee No. 2	1,280,000	Nuclear	100	1992			
(Northeast of Spartanburg, in South Carolina)							

(1) Based on past experience, operational dates may vary due to changes in load forecasts, construction delays, difficulties which may be encountered in obtaining regulatory approvals or in obtaining capital at reasonable costs, and other factors (see "Business—Regulation").

(2) These amounts exclude the costs of initial fuel cores. The estimated construction costs per KW for the McGuire and Cherokee Nuclear Stations reflect increases of approximately 10% and 59%, respectively, over the most recently published estimates, resulting from a deferral of the dates of planned operation, costs arising from more stringent regulatory requirements, inflationary factors and, in the case of the Cherokee Nuclear Station, reallocation of costs occasioned by the Company's decision to defer construction of the third unit.

(3) These amounts do not include the costs of a 75% undivided interest in Unit No. 2 and a 37½% undivided interest in the support facilities sold to the North Carolina Municipal Power Agency Number 1 and assume no further sale of any portion of the Company's remaining interest in the Catawba Nuclear Station.

The Atomic Energy Commission, whose licensing and regulatory functions have been assumed by the Nuclear Regulatory Commission (NRC), issued construction permits in 1973 for both units of the McGuire Nuclear Station. An operating license is required before such units can be placed into commercial operation. On April 18, 1979, the Atomic Safety and Licensing Board of the NRC issued a partial initial decision which approved the issuance of an operating license for such units. However, the Board stayed the effectiveness of the decision and retained jurisdiction pending review of the NRC staff analysis of unresolved generic safety matters. Certain intervenors who had unsuccessfully opposed the issuance of construction permits are continuing to oppose the Company's application for operating licenses for such units (see also "Business—Regulation—*Nuclear Facilities*").

The NRC issued construction permits for the Catawba Nuclear Station in 1975 and for the Cherokee Nuclear Station in 1977.

In order to reduce its need for external financing, the Company, in 1978, sold to the North Carolina Municipal Power Agency Number 1 (NCMPA), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit No. 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. The sale was at cost plus a profit associated with the interest sold (see note 10 of Notes to Financial Statements). The Company will continue to construct Unit No. 2, and the NCMPA will finance its portion of the construction costs by continued monthly progress payments. The transaction contemplates that the Company will operate the Unit, interconnect its transmission system with it, wheel a certain portion of the capacity and energy of such Unit to the municipal participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the municipal participants, and provide supplemental power as required by the NCMPA to enable it to provide service on a firm basis to the participating municipalities. The Company will also maintain a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station commencing as early as 1982 under certain circumstances.

The Company has agreed in principle to sell to a joint agency of its South Carolina municipal customers the remaining 25% interest in Unit No. 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to the NCMPA. This agency, the Piedmont Municipal Power Agency (PMPA), was formed under legislation recently enacted by the South Carolina General Assembly. A lawsuit testing the constitutionality of such legislation is expected to be filed later this year. Any such sale would be subject to the upholding of the constitutionality of such legislation and obtaining the necessary financing and regulatory approvals, as well as participation by a minimum number of the members of the PMPA.

The Company is also negotiating with a group of its cooperative customers to sell a 75% undivided interest in Unit No. 1 of the Catawba Nuclear Station. Any such sale would be subject to obtaining the necessary financing and regulatory approvals and meeting certain financial feasibility requirements.

During 1979, the NCMPA's participating municipalities, which are presently wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and the proposed purchasers of the balance of Unit No. 2 accounted for approximately 2% of KWH sales and approximately 2% of revenues. The proposed purchasers of Unit No. 1 of the Catawba Nuclear Station accounted for approximately 6% of KWH sales and approximately 5% of revenues. There is no assurance that such proposed sales to PMPA or to the cooperative customers will be consummated and, to the extent that such sales are not consummated, the Company intends to complete and operate such Units as part of its system.

Planned Facilities

The Company has obtained a license from the Federal Power Commission, whose licensing and regulatory functions have been assumed by the Federal Energy Regulatory Commission (FERC), to construct the Bad Creek Hydroelectric Station, a pumped storage facility in Oconee County, South Carolina. Such facility, which is expected to have a generating capability of 1,000,000 KW, is scheduled for completion in the early 1990s but may be placed into service earlier if required. The total cost of such facility is expected to be approximately $652 million, of which $7.7 million was expended through December 31, 1979 and an additional $1.7 million is expected to be incurred through December 31, 1980.

The Company also has plans to build a third unit of the Cherokee Nuclear Station but has not scheduled its construction or exercised its options for the purchase of the major components.

In addition, the Company presently has plans to construct an additional nuclear generating facility, southwest of Winston-Salem in North Carolina, to be known as the Perkins Nuclear Station. Such facility, which would be virtually identical to the Cherokee Nuclear Station, would consist of three generating units. The planned operating dates for such facilities have not been scheduled.

The Company has applied to the NRC for a construction permit for the Perkins Nuclear Station. Active opposition has been encountered at the environmental hearings for such permit and such opposition is continuing. The North Carolina Utilities Commission has issued a certificate of convenience and public necessity for such facility, which included certain restrictions requested by the North Carolina Environmental Management Commission on use of water from the Yadkin River.

General

The complexity of present-day electric utility technology and the time required for the construction of generating facilities and for the completion of the licensing and other regulatory proceedings relating thereto have compelled the Company, as well as other electric utilities, to make substantial investments in the construction of such facilities prior to the completion of licensing and regulatory proceedings. At December 31, 1979 the Company had expended approximately $2 billion for the McGuire, Catawba and Cherokee Nuclear Stations, for which only construction permits have as yet been issued, and $10.8 million for the Perkins Nuclear Station, for which no such permit has yet been issued. Under present NRC procedures, an operating license may be issued only when construction of a nuclear unit has been completed (see "Business—Regulation—*Nuclear Facilities*"). Accordingly, the Company is necessarily making substantial investments in its facilities before regulatory proceedings are completed. There is no assurance that the necessary operating licenses and authorizations will be issued for such facilities.

Opposition to Nuclear Power Development

The development of nuclear power continues to be a subject of public controversy, particularly in the aftermath of the Three Mile Island accident (see "Business—Regulation—*Nuclear Facilities*"). Various groups have engaged in public protests, filed suits and participated in administrative proceedings and other activities, claiming that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. In addition, restrictive legislation relating to nuclear power has been proposed in Congress and in several state legislatures. Some of the claims made by such groups, if they should prevail, or the existence of the controversy itself, could delay or prevent the construction of nuclear generating units presently planned or under construction, or cause substantial modifications to or extended shutdowns of existing units.

The Company's studies continue to support its conclusion that the generation of electricity by nuclear power will be more economical than generation by fossil fuel, and the Company believes that its present construction program is compatible with the protection of the environment.

BUSINESS

Service Area

The Company supplies electric service directly to approximately 1,253,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to 37 other incorporated municipalities and to a number of rural electric cooperatives and private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco, furniture and chemical industries are of major significance to the economy of the area, and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, food products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $254 million of the Company's revenues in 1979, representing 17% of electric revenues and 50% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1979, its generation of electric energy for 1979 and certain corresponding information presently projected for 1980:

			Generating Capability(1)			Generation		
			Actual 1979		Projected 1980 (2)	Actual 1979		Projected 1980 (2)
Source	Facility		KW	%	%	KWH	%	%
						(millions)		
Coal	Belews Creek		2,240,000			12,393		
	Marshall		1,900,000			11,197		
	Allen		1,100,000			5,134		
	Cliffside		770,000			3,181		
	Others		1,407,000			5,499		
		Total	7,417,000	61.6	56	37,404	68.5	65
Nuclear	Oconee		2,580,000	21.4	21	14,228	26.1	27
	McGuire(3)		—	—	7	—	—	6
		Total	2,580,000	21.4	28	14,228	26.1	33
Hydro	26 stations		1,452,000	12.0	11	2,809	5.1	2
Oil and Gas	Combustion turbines		599,000	5.0	5	163	0.3	—
		Total	12,048,000	100.0	100	54,604	100.0	100

(1) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(2) Projected figures are based on the assumption that required fuel is available and that there are no unforeseen contingencies.

(3) Unit No. 1 of the McGuire Nuclear Station, with a net capability of 1,180,000 KW, is scheduled for operation in late 1980 (see "Regulation—*Nuclear Facilities*").

According to industry statistics through 1977 maintained by the Department of Energy, the Company ranked first in the nation for the last four consecutive years and for six of the last eight years through 1977 in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. The Company's Belews Creek and Marshall Steam Stations were ranked as the first and third most efficient steam-fossil generating stations in 1977. Unit No. 3 of the Oconee Nuclear Station had the best heat rate in 1978 of all nuclear units in the nation according to statistics supplied by utilities to the

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NRC. Unit No. 1 ranked fourth in the nation as did the Oconee Nuclear Station itself. In prior years, operating reliability and availability of such nuclear units have been comparable to the average experience of the industry for units of similar size and vintage. The net capacity factors for the Oconee Nuclear Station were 68%, 57%, 58%, 70% and 63% for 1975, 1976, 1977, 1978 and 1979, respectively.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1979-1980 winter peak load to date of 9,892,000 KW occurred on February 5, 1980, and the 1979 summer peak load of 9,833,000 KW occurred on August 9, 1979. The 1978-1979 winter peak load of 9,844,000 KW occurred on January 4, 1979, and the 1978 summer peak load of 9,472,205 KW occurred on June 28, 1978.

Federal Energy Legislation

Congress adopted a national energy act in 1978 dealing with, among other things, utility rate design, including restrictions on the use of fuel adjustment clauses. Other sections of the legislation give FERC increased authority to order interconnections, power pooling and wheeling of power. The Company is presently unable to assess the impact of this legislation on its operations.

Rate Matters

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSC) must approve the Company's rates for retail sales within the respective States. FERC must approve the Company's rates for sales under its wholesale rate schedules.

General Rate Increases. The following table sets forth information concerning all rate increases requested or implemented by the Company during the five-year period 1975-1979. The revenues (in millions of dollars) shown are annualized on the basis of the filing test year.

Jurisdiction and Date Filed	Requested Revenues	Approved				End of 12-Month Test Period
		Revenues	% of Request	% of Increase Over Previous Revenues	Rate Order Effective(1)	
N. C. Retail:						
November 1974	$122.7	$111.3	90.7	23.6	October 1975	December 31, 1974
January 1978(2)	70.5	40.3	57.2	5.3	September 1978	September 30, 1977
March 1979(3)	35.5	28.3	79.7	3.2	October 1979	December 31, 1978
S. C. Retail:						
May 1974	54.3	47.7	87.8	22.8	January 1976	December 31, 1974
April 1978(4)	34.5	18.2	52.8	5.4	June 1979	December 31, 1977
August 1979(5)	25.8	—	—	—	—	June 30, 1979
FERC Wholesale:						
January 1973	8.9	8.9	100.0	18.1	August 1975	December 31, 1972
May 1975	23.6	22.7	96.2	22.0	August 1976	December 31, 1975
June 1978(6)	15.3	15.0	98.0	9.3	January 1980	December 31, 1978

(1) The Company has generally collected interim rate increases, subject to refund, in all three jurisdictions. On occasion the Company has implemented its entire request on such a basis prior to the final rate order.

(2) Revenues for 1978 and for 1979 include approximately $12.7 million and $43.3 million, respectively, attributable to this rate increase.

(3) Revenues for 1979 include approximately $6.8 million attributable to this rate increase.

(4) Revenues for 1978 and for 1979 include approximately $8.6 million and $18.9 million, respectively, attributable to this rate increase.

(5) This request was implemented in its entirety, subject to refund, on October 8, 1979, and approximately 80% of the increased billings (approximately $4.9 million through December 31, 1979) has been recorded as revenues.

(6) Revenues for 1978 and for 1979 include approximately $2.5 million and $10.5 million, respectively, attributable to this rate increase.

The Company has not been able to earn the rates of return as allowed and defined by the NCUC and the PSC in recent rate proceedings since orders resulting therefrom were based on historical cost during inflationary periods. In the Company's most recent rate proceedings, the NCUC allowed a rate of return on common equity of 13.60% and the PSC allowed a rate of return on common equity of 12.75%.

The Company filed an application on February 29, 1980 with the NCUC to increase retail revenues by approximately 9.6%. If approved, such rates would produce additional revenues of approximately $92 million based on the test year ended December 31, 1979. The request, which provides for a return on common equity of 15% and an attrition allowance to offset the effects of inflation, seeks, for the first time, the inclusion in rate base of construction work in progress. Such treatment is required by a North Carolina statute with respect to construction expenditures made after July 1, 1979 and included in rate applications after such date (see note 1 of Notes to Financial Statements). Other legislation requiring that, for ratemaking purposes, the NCUC utilize in any rate application filed on or after July 1, 1979 "reasonable original cost" in valuing utility assets instead of the prior "fair value standard" is not expected to adversely affect the Company. The Company anticipates placing into effect all or a portion of the requested increase, subject to refund, during the fourth quarter of 1980 if the NCUC has not acted by that time. Applications for parallel rate increases with respect to its wholesale and South Carolina retail customers are expected to be filed later this year.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The procedures for wholesale customers entail a 60-day lag from the date changes in fuel expense occur until they are reflected in bills to such customers. Beginning February 1, 1980, the procedures for North Carolina retail customers were modified to set the base fuel factor on a prior four months' experience and to limit changes in this factor to four-month intervals. The NCUC also will review the operation of the Company's base load generating facilities if its nuclear units generate at a capacity factor of less than 60%, in which event the Company has the specific burden of justifying the recovery of its incremental fuel costs. Effective June 1, 1979, the fuel cost recovery procedures for South Carolina retail customers were modified to set the base fuel factor semiannually after a public hearing to review fuel costs. The semiannual review will take into consideration fuel costs experienced during the preceding six months as well as fuel costs projected for the subsequent six months.

Fuel Supply

The Company presently relies principally on coal for the generation of electric energy, but it anticipates relying on nuclear power to a greater extent in the future (see "Construction Program"). The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source — Year Ended December 31					Average Cost per Million BTU on a Burned Basis — Year Ended December 31				
	1975	1976	1977	1978	1979	1975	1976	1977	1978	1979
Coal	61.0%	70.6%	71.0%	65.4%	68.5%	115.45¢	110.80¢	127.95¢	144.46¢	148.86¢
Nuclear	33.0	25.5	24.9	30.0	26.1	19.67	21.29	24.44	33.32	38.51
Oil and Gas	.1	—	.6	.9	.3	169.60	231.63	239.47	262.76	246.16
All Fuels (cost based on weighted average)	94.1	96.1	96.5	96.3	94.9	79.55	85.08	100.38	109.09	116.81
Hydroelectric*	5.9	3.9	3.5	3.7	5.1					
	100.0%	100.0%	100.0%	100.0%	100.0%					

* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

Coal. The Company obtains its coal under long-term supply contracts with mining operators utilizing both deep and surface mining, through its own mining operations, all of which are deep mine, and by open market purchases. During 1979, the Company obtained its coal requirements approximately as follows: 74% (10.9 million tons) under long-term contracts, 14% (2.1 million tons) from its own mining operations and 12% (1.8 million tons) by open market purchases.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1980 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. In order to further assure its coal supply, the Company has invested in independent coal mining operations located in eastern Kentucky.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. The Company purchased coal on a spot basis at an average delivered cost of $30.64 per ton, or 127.0¢ per million BTU, in 1979, as compared with an average delivered cost of $32.67 per ton, or 136.4¢ per million BTU, in 1978.

The Company has estimated recoverable coal reserves from its own mining operations of approximately 234,500,000 tons. Such reserves, approximately 90% of which are deep mineable, represent the amounts of coal that can be expected to be recovered from total coal reserves "in place" after allowing for unavoidable coal losses during mining operations and for coal necessarily left in the ground for safety and other purposes. The mining recovery factors used are 70% for deep mining, 40% for auger mining, 90% for surface mining and a washing recovery of 95%. The reserves are no less than "probable", lie within 5,000 feet from a known seam measurement, are "assigned" and represent recoverable tonnage which can be produced through existing facilities.

Additional coal tonnage of similar quality has been established at the Company's mining operations, but a determination of the degree to which this coal could be commercially mineable would require further evaluation which the Company does not intend to undertake at this time.

Federal legislation relating to the regulation of surface mining of coal was enacted in 1977. Such legislation, among other things, establishes standards restricting the surface mining of coal, requires the restoration of lands affected by surface mining and imposes a tax based upon the tonnage of coal mined to be used for the restoration of abandoned areas. This legislation is adversely affecting the price of coal to the Company. It is anticipated that in 1980 approximately 33% of the Company's coal supply will be provided through surface mining operations as compared with 49% in 1979.

As the Company is heavily dependent on coal for the generation of electricity, it endeavors to maintain an average coal supply of approximately 90 days. On March 21, 1980, the Company had on hand a coal supply of approximately 76 days. During the last five years, the Company's average coal inventories were as follows: 1975—89 days, 1976—95 days, 1977—73 days, 1978—61 days and 1979—94 days.

The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the emission limitation for sulfur dioxide of 2.3 pounds per million BTU of heat input for existing facilities (see "Regulation—*Environmental Matters*").

The Company estimates that through the year 2000 its existing coal-fired generating units (see table under "Energy Requirements and Capability") will burn a total of approximately 250 million tons of coal. The Company presently expects to obtain approximately 20% of this estimated requirement from its own mining operations and has long-term agreements which, upon renewal as needed, would substantially provide the balance. The Company anticipates that, when fully developed, its own mining operations will provide approximately 2.3 million tons of coal a year.

The Economic Regulatory Administration of the Department of Energy is authorized, under prescribed conditions, to allocate coal to achieve, among other things, the distribution of available low sulfur fuels on a priority basis to areas designated by the United States Environmental Protection Agency (EPA).

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any

time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations (see "Energy Requirements and Capability" and "Construction Program") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1990	1987	2009	1988
McGuire	1990	1987	2009	1988
Catawba	1990	1987	2009	1989

The Company has contracted for sufficient uranium material for the initial cores of Unit Nos. 1 and 2 of the Cherokee Nuclear Station and for enrichment services through 2011. The Company also has options to provide such Units with fabrication services through the mid-1990s. Options are also under consideration which would provide the Company with conversion services for its entire system through the late 1980s.

Approximately 75% of the Company's commitments for uranium materials included in the preceding table is expected to be obtained from Rio Algom, Ltd., a Canadian supplier. Before making deliveries to the Company, such supplier must secure permits and export licenses from various Canadian governmental agencies, including the Atomic Energy Control Board, the Department of Industry, Trade and Commerce and the Uranium Exports Review Panel.

The Company purchased uranium material during 1979 at an average price of approximately $20 per pound. However, such price is expected to be substantially greater in future years. The Company's material nuclear supply contracts generally contain *force majeure* provisions and provide for price escalation under certain conditions.

The Company is endeavoring to obtain other fuel commitments although it cannot predict whether it will be successful or estimate the costs involved. As a part of its efforts to obtain additional sources of uranium at a reasonable cost, a wholly-owned subsidiary of the Company, Western Fuel, Inc., has entered into a joint venture in central Wyoming with Ogle Petroleum Inc., which is acting as operator. Such venture has established the feasibility of a new method for extracting uranium ore and has begun construction of the first phase of a plant for commercial operation scheduled to begin in mid-1980. Western Fuel's share of the cost of the plant, to be completed in the latter part of 1982, is estimated to be approximately $6 million.

The Company has expended approximately $5 million to date in connection with this venture. The amount of uranium presently estimated to be available from the project for the Company's use as a percentage of its presently estimated requirements over the life of the project is approximately 5%.

Although the reprocessing of spent fuel would make available to the Company an additional 20% of its nuclear fuel needs through 1990, there are currently no commercial reprocessing facilities in operation in the United States, and operations, such as those of Allied General Nuclear Services with whom the Company has a contract for reprocessing services through 1984 for certain of its nuclear stations, cannot commence until appropriate licenses are received from the NRC. The utilization of such facilities is dependent upon certain regulatory and policy decisions to be made by the Federal government. The President has announced that he opposes the reprocessing of spent fuel but supports the development of spent fuel storage facilities, and the Department of Energy has announced plans pursuant to which the Federal government would accept unreprocessed spent fuel and assume title to the material and responsibility for its storage and disposal in return for which the Company would pay a one-time charge. If reprocessing of spent fuel becomes available in the future, the stored spent fuel could be retrieved or the Company could receive compensation for the net value of such fuel.

The Company has adequate facilities for storage in the spent fuel pools at its Oconee Nuclear Station through mid-1982. The Company is presently involved in increasing storage facilities at such Nuclear Station at a cost of approximately $3 million in the Company's 1980-1982 construction program which would extend its capability until 1986. The Company has applied for a license to store spent fuel from the

Oconee Nuclear Station in the spent fuel pool at the McGuire Nuclear Station currently under construction. Intervenors have opposed the granting of such license. The Company is also enlarging the capacity of the spent fuel pools at the McGuire and Catawba Nuclear Stations to accommodate larger amounts of spent fuel. Such modifications, which are estimated to cost about $4 million in the Company's 1980-1982 construction program, will enable the Company to have adequate facilities for the storage of its spent fuel until approximately 1990.

See "*Depreciation and Amortization*" under note 1 of Notes to Financial Statements for additional information regarding nuclear fuel costs.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC and EPA and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities (see "Construction Program"). The coal mining operations of Eastover Mining Company, the Company's coal mining subsidiary, are subject to the Coal Mine Health and Safety Act of 1969.

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1980-1982 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $133 million, including $45 million in 1980 and $42 million in 1981. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

Air Quality. In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing standards limiting such emissions which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans.

With respect to particulate emissions, the implementation plans require compliance with an opacity standard based on the visual density of the flue gas and a mass emissions standard stated in terms of pounds per million BTU of heat input. Although the Company believes it has installed the best available control technology in its coal-fired generating stations, it determined that it could not consistently and continuously meet the stringent North Carolina implementation plans even though each unit had successfully completed stack performance tests. Some difficulties were encountered with the emission control systems when a unit was being brought up to normal operating capacity or was in the process of being cooled down.

The Company filed for a variance from the maximum particulate emission limitations, which variance was granted by the North Carolina Environmental Management Commission and submitted to EPA as a revision to the State's implementation plan. In granting the variance, such Commission found that the Company had installed the best available control technology at its coal-fired generating stations and that independent air monitoring and modeling studies indicated that the emission limitations could be modified without violating State and Federal ambient air quality standards. Unless the implementation plan is modified as requested by such Commission, it is estimated that the Company could incur capital expenditures of as much as $224 million for additional control equipment. In addition, Federal administrative non-compliance penalties may be incurred until such additional equipment can be installed and such units may not be operated at full capacity or may be unavailable for use from time to time. On February 14, 1980, EPA published a notice in the Federal Register proposing approval of the revision of the mass emission standard and providing for public comment on its proposed action. The revised

standards pending before EPA provide for an opacity standard of 40%, and the mass emission standard for particulates provides a maximum limitation of 0.20 to 0.25 pounds per million BTU of heat input.

In 1974 EPA issued regulations, applying to the construction or expansion of facilities commenced after June 1, 1975, establishing a mechanism for "prevention of significant air quality deterioration" in areas where air pollution levels of sulfur dioxide and particulate matter are below the national ambient air quality standards. Amendments to the 1970 Act, adopted in 1977, include, among other things, requirements substantially similar to such regulations. The amendments also require EPA to establish stringent restrictions on emissions in non-attainment areas, to update new source performance standards for specified pollutants and to require the use of the best available technology rather than clean fuels to control emissions. The amendments also authorize EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and new civil penalties of up to $25,000 per day of violation for facilities found to be in violation of an applicable implementation plan. EPA has promulgated new performance standards under these amendments which will apply to all stations not presently under construction and will require the use of scrubbers to remove sulfur dioxides, as well as other techniques to remove nitrogen oxides and particulate matter emissions. These amendments and proposed standards will affect the lead time, size and siting of future fossil-fueled generating stations as well as the type, complexity and cost of pollution control equipment to be used.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1972 (the 1972 Act) provided for the imposition of effluent limitations to regulate discharges of pollutants, including heat, into the waters of the United States. The 1972 Act mandated that there be achieved by July 1, 1977, with respect to existing plants, effluent limitations requiring application of the "best practicable control technology currently available" as well as compliance with state water quality standards. The Company has complied with these requirements. Regulations proposed under the 1972 Act also prescribed that the location, design and construction of cooling water intake structures reflect the "best technology available for minimizing environmental impact".

The 1972 Act required permits to ensure compliance with its provisions. The Company has received such permits for all of its generating stations either from EPA or under the permit programs of the States of North Carolina and South Carolina which have been approved by EPA.

In 1974 EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines required certain limitations on chemical discharges and imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit *(Appalachian Power Company, et al., v. Train)*. In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement and certain chemical limitations. The Company is unable at this time to determine what effect these developments will have on its operations.

In 1977 Congress adopted the Clean Water Act of 1977 (the 1977 Act) which amended the 1972 Act. The 1977 Act provides for three categories for controlling pollution: (1) conventional pollutants will require treatment by the best conventional pollutant control technology by July 1, 1984; (2) toxic pollutants will require application of the best available technology economically achievable by July 1, 1984; and (3) non-conventional pollutants will require application of the best available technology economically achievable within three years after effluent limitations are established, but no later than July 1, 1987. The 1977 Act also authorizes EPA to publish regulations to control station site runoff, spillage, leaks, sludge or waste disposal, and drainage from raw material storage which is associated with or ancillary to the source. The Company will be unable to determine the effect, if any, such legislation will have on its operations until the required regulations are promulgated.

OTHER ENVIRONMENTAL REGULATIONS. North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities.

Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. South Carolina also has proposed regulations implementing its Hazardous Waste Management Act. The Company is unable to determine the effects, if any, that such regulations will have on its operations.

The Company is subject to the Toxic Substances Control Act and the rules and regulations promulgated thereunder relating to the disposition of fly ash. The Company is also aware that certain of its activities may be subject to the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, pursuant to which EPA is presently promulgating regulations. The Company is unable to determine the effects, if any, that such regulations will have on its operations.

GENERAL. Environmental regulations are in the process of development. Accordingly, the Company cannot estimate the effect of existing and potential regulations upon any of its existing and proposed facilities. However, developments in these and other areas of regulation have in the past required the Company to modify or replace equipment and may in the future delay construction and operation of new or existing facilities at costs which could be substantial.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations permit public intervention with respect to such issues in proceedings relating to applications for permits or licenses. The operating licenses for the Oconee Nuclear Station and the construction permits for the McGuire, Catawba and Cherokee Nuclear Stations were granted after completion of the environmental review required of the NRC under the National Environmental Policy Act of 1969 (see "Construction Program").

In March 1979, Unit No. 2 of the Three Mile Island Nuclear Station, located near Harrisburg, Pennsylvania, experienced severe operating difficulties resulting in the shutdown of the Unit and presently undetermined damage to the reactor core. The nuclear steam supply system of such Unit is of Babcock & Wilcox design and manufacture as are those of the three units of the Company's Oconee Nuclear Station (see "Energy Requirements and Capability"). The nuclear steam supply systems of the Company's other nuclear generating facilities under construction or in the planning stage are of a different design and manufacture.

The Three Mile Island accident is causing a reexamination of certain safety standards and procedures for nuclear facilities and has led to an overall reassessment of nuclear power by various governmental entities, including consideration of a possible moratorium on construction or licensing of nuclear facilities and shutdowns of existing facilities under certain circumstances.

A Commission appointed by the President to investigate this accident has issued a report dated October 30, 1979 recommending, among other things, that the NRC be reorganized and that the NRC or its successor should, on a case-by-case basis, before issuing a new construction permit or operating license with respect to a nuclear generating plant: (a) assess the need to introduce new safety improvements recommended in such report and in NRC and industry studies; (b) review the competency of the prospective operating licensee to manage a nuclear plant and the adequacy of its training program for operating personnel; and (c) condition licensing upon review and approval of state and local emergency plans. In testimony before a Congressional committee in November 1979, the Chairman of the NRC indicated that the NRC would not issue construction permits or operating licenses for at least six months or possibly for as long as two years in order to provide an opportunity to study and implement parts of such report and similar studies.

In December 1979, the President announced that he agreed with the intent of the recommendations made in the Commission's report but proposed certain modifications to the recommendations for a restructuring of the NRC. The President also endorsed the delay in issuing new operating licenses and construction permits in order to implement reforms but urged that such work be completed no later than mid-1980.

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In January 1980, a committee appointed by the NRC and known as the Special Inquiry Group issued its report in which it criticized the NRC and the nuclear power industry.

The Company's present schedule contemplates receipt of an operating license for its McGuire Nuclear Station so that Unit No. 1 can commence operations in late 1980. This schedule will be extended if the license is not granted on a timely basis. However, a substantial delay in such licensing will have an adverse impact on the Company's reserve margins, cash flow and financing program.

The NRC issued a license to the Tennessee Valley Authority for Unit No. 1 of its Sequoyah Nuclear Station on February 29, 1980, authorizing fuel loading, proceeding to initial criticality, performing start-up testing at zero power and, after prior written approval of the director of Nuclear Reactor Regulation, operating the facility at a maximum of 5% of rated power. This Unit of the Sequoyah Nuclear Station is of the same manufacture and is substantially similar to Unit No. 1 of the McGuire Nuclear Station.

Certain modifications of pipe support systems required by the NRC relating to seismic considerations have been completed on Unit Nos. 1 and 3 of the Oconee Nuclear Station. Similar modifications are being effected on Unit No. 2 during the scheduled refueling outage which began earlier this month and which is expected to continue until June of this year. The cost of such modifications is estimated at $16 million.

As a result of the Three Mile Island accident, the NRC has developed an extensive list of requirements for the operation of nuclear facilities. On January 2, 1980 the NRC issued an order requiring the Company to implement certain of such requirements with respect to Unit Nos. 2 and 3 of the Oconee Nuclear Station by February 15, 1980 or to shut down such Units. These requirements include the installation of indicators on certain relief valves and automatic isolation of containment buildings from low primary coolant pressure. The modifications have been completed on Unit No. 1, and the Company had obtained authorization for phased implementation for Unit Nos. 2 and 3 in order to avoid a simultaneous outage of both Units during likely peak power demand periods. The Company anticipates completion of the modifications on Unit No. 3 next month and on Unit No. 2 in June. The cost of such modifications is estimated at $1.2 million.

The Company cannot predict what other effects this accident may have upon it, upon its ability to finance, upon the construction, licensing, cost or future operations of its nuclear units or upon the Price-Anderson Act and the nuclear liability system.

The Company has insured against public liability claims resulting from nuclear incidents by purchasing the maximum available private insurance of $160 million, and the remaining $400 million of the $560 million limit on liability under the Price-Anderson Act has been provided by an indemnity agreement with the NRC. Effective in 1977 the NRC's indemnity began to be phased out in favor of a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors, and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance and indemnity coverage do not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $300 million, or the insurable value of the facilities, whichever is less. In connection with the sale of a portion of its interest in the Catawba Nuclear Station (see "Construction Program"), the Company placed through a pool of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of the maximum coverage available.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Certain hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that upon the expiration of any

license issued thereunder the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which the Company considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

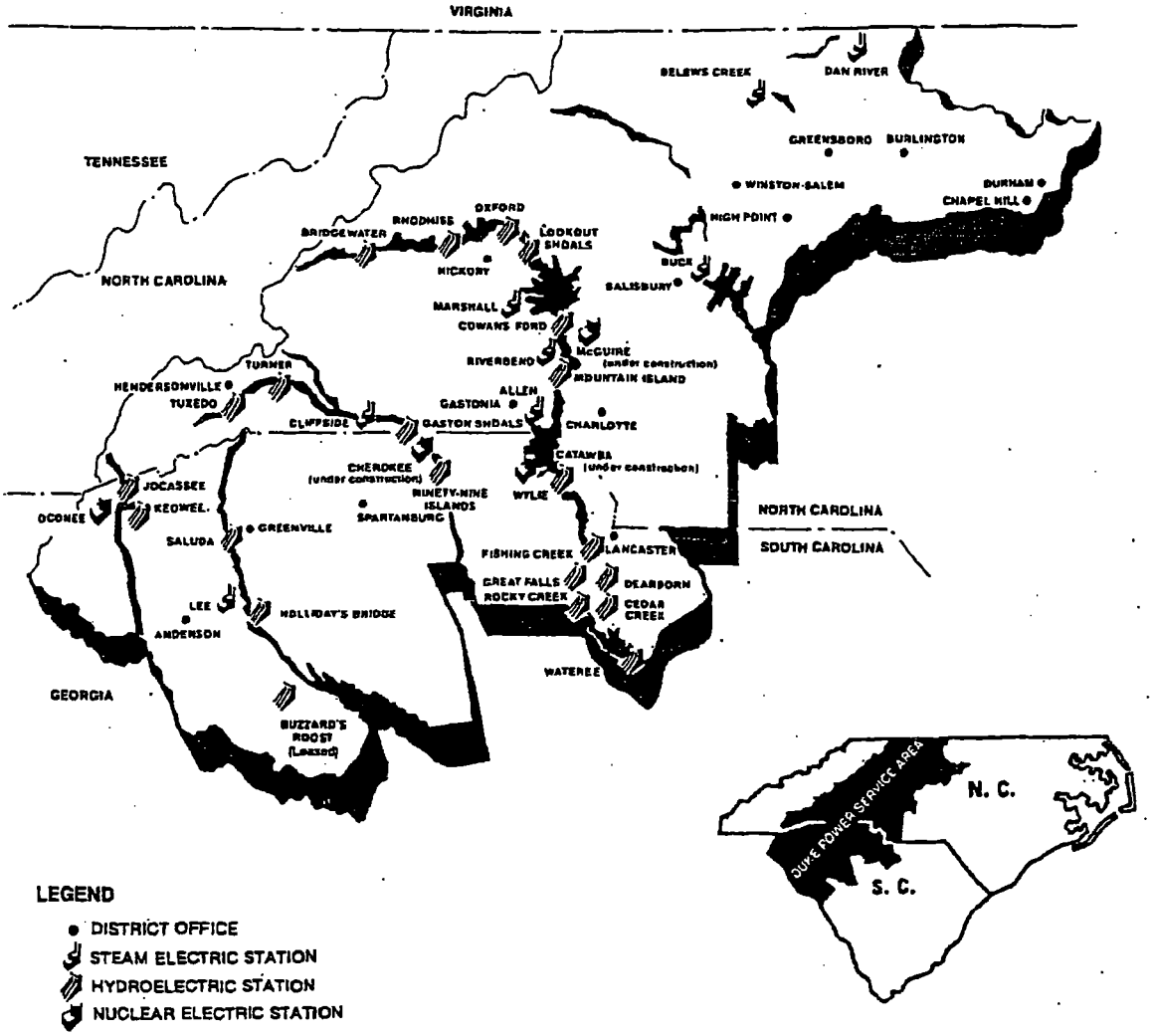
Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Legislation in North Carolina and South Carolina provides for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. The North Carolina Supreme Court rendered a decision in 1974 which, in some instances, limits the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

Employees

The Company employs approximately 19,300 persons, of whom approximately 8,600 are engaged in generating plant construction including design and engineering. About 1,750 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW) with which the Company has a labor agreement which expires on September 30, 1980. The Company's coal mining subsidiary, Eastover Mining Company, employs approximately 1,000 persons, the majority of whom is represented by labor unions, including the United Mine Workers of America.

Duke Power Service Area



OPERATING STATISTICS

	Year Ended December 31					
	1975	1976	1977	1978	1979	%
Sources of Electric Energy—						
Millions of kilowatt-hours:						
Generated—net output:						
Coal	28,202	35,875	37,184	34,589	37,404	68.5
Nuclear	15,290	12,978	13,008	15,905	14,228	26.1
Hydro	2,736	1,961	1,852	1,941	2,809	5.1
Oil and gas	57	13	303	484	163	.3
Total generated	46,285	50,827	52,347	52,919	54,604	100.0
Net interchange and purchased power	(776)	(1,656)	31	1,016	(512)	
Losses and company use	(3,371)	(3,538)	(3,530)	(3,996)	(3,769)	
Total energy sales	42,138	45,633	48,848	49,939	50,323	
Average Cost Per Ton of Coal Burned	$26.91	$26.21	$30.00	$34.24	$35.86	
Electric Energy Sales—						
Millions of kilowatt-hours:						
Residential	10,806	11,327	12,462	12,959	12,832	25.5
General service	7,567	7,987	8,623	8,920	8,778	17.4
Industrial	16,736	18,417	19,188	19,523	20,260	40.3
Wholesale and other energy sales	7,029	7,902	8,575	8,537	8,453	16.8
Total energy sales	42,138	45,633	48,848	49,939	50,323	100.0
Electric Revenues—						
Thousands of dollars:						
Residential	$324,437	$ 372,348	$ 424,081	$ 469,389	$ 499,936	33.5
General service	200,292	227,867	256,439	284,752	303,858	20.4
Industrial	315,286	361,310	402,003	448,550	508,605	34.1
Wholesale and other energy sales	124,692	149,094	173,832	188,428	201,938	13.5
Other electric revenues	(34,323)	(2,261)	10,619	5,601	(21,780)	(1.5)
Total electric revenues	$930,384	$1,108,358	$1,266,974	$1,396,720	$1,492,557	100.0
Number of Customers End of Period—						
Residential	969,863	989,501	1,024,712	1,049,543	1,078,419	86.0
General service	144,458	149,240	155,716	159,538	161,833	12.9
Industrial	6,626	6,752	6,947	7,231	7,475	.6
Wholesale and other energy sales	5,312	5,472	5,688	5,857	5,950	.5
Total customers	1,126,259	1,150,965	1,193,063	1,222,169	1,253,677	100.0
Residential Customer Statistics—						
Average number for period	961,664	982,548	1,016,482	1,039,275	1,068,194	
Average annual use—KWH	11,237	11,528	12,260	12,469	12,013	
Average annual billing	$337.37	$378.96	$417.20	$451.65	$468.02	
Average Annual Billed Revenue Per KWH—						
Residential	3.00¢	3.29¢	3.40¢	3.62¢	3.90¢	
General service	2.65¢	2.85¢	2.97¢	3.19¢	3.46¢	
Industrial	1.88¢	1.96¢	2.10¢	2.30¢	2.51¢	
Wholesale and other energy sales	1.77¢	1.89¢	2.03¢	2.21¢	2.39¢	

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Item 2. *Summary of Operations.*

DUKE POWER COMPANY

STATEMENT OF EARNINGS

The following statement of earnings has been examined by Deloitte Haskins & Sells, independent auditors, whose opinion with respect thereto is included elsewhere herein. The statement should be read in conjunction with its notes and the other financial statements and their notes appearing elsewhere herein.

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Electric Revenues (note a)	$930,384	$1,108,358	$1,266,974	$1,396,720	$1,492,557
Electric Expenses					
Operation—					
Fuel used in electric generation	338,024	399,770	493,818	543,319	589,402
Net interchange and purchased power (credit)	(11,588)	(28,815)	(318)	17,271	(17,254)
Wages, benefits and materials	105,890	118,834	139,674	155,443	180,338
Maintenance of plant facilities	40,968	45,369	61,874	78,605	94,598
Depreciation and amortization (note 1)	100,995	110,644	114,974	120,839	125,437
General taxes (note 12)	75,757	85,215	95,309	103,816	112,655
Income taxes (notes 1 and 8)	92,542	143,924	131,757	140,426	153,504
Total electric expenses	742,588	874,941	1,037,088	1,159,719	1,238,680
Electric operating income	187,796	233,417	229,886	237,001	253,877
Other Income					
Allowance for all funds used during construction (note 1)	54,794	61,725	—	—	—
Allowance for equity funds used during construction (note 1)	—	—	62,441	87,810	121,701
Earnings of subsidiaries, net (note 2)	197	4,582	8,881	9,159	10,447
Other, net (deduction) (note 10)	(1,666)	265	(658)	16,168	(20,314)
Income taxes—other, net (notes 8 and 10)	930	640	778	(16,963)	16,320
Income taxes—credit (notes 1 and 8)	20,859	22,323	25,513	35,725	40,458
Total other income	75,114	89,535	96,955	131,899	168,612
Income before interest deductions	262,910	322,952	326,841	368,900	422,489
Interest Deductions					
Interest on long-term debt	135,289	144,749	152,496	165,926	179,363
Other interest	10,478	4,502	6,390	6,533	9,752
Allowance for borrowed funds used during construction (credit) (note 1)	—	—	(24,394)	(34,160)	(41,386)
Total interest deductions	145,767	149,251	134,492	138,299	147,729
Net Income	117,143	173,701	192,349	230,601	274,760
Dividends on preference and preferred stocks	34,344	34,990	38,879	46,632	52,562
Earnings for Common Stock	$ 82,799	$ 138,711	$ 153,470	$ 183,969	$ 222,198
Common Stock Data					
Earnings per share (note b)	$1.62	$2.40	$2.41	$2.61	$2.88
Dividends per share	$1.40	$1.525	$1.63	$1.74	$1.83

Numerical note references are to Notes to Financial Statements.

DUKE POWER COMPANY

NOTES TO STATEMENT OF EARNINGS

(a) *Rate Matters.* For information relating to general rate increases and fuel cost adjustment procedures for wholesale and retail customers, see Item 1.—"Business—Rate Matters".

(b) *Earnings Per Share.* Earnings per share of common stock are calculated by dividing earnings for common stock by the average number of common shares outstanding, which was 51,020,000 for 1975, 57,767,000 for 1976, 63,630,000 for 1977, 70,367,000 for 1978 and 77,168,000 for 1979. Conversion of the Preference Stock, 6¾% Convertible Series AA, would not have a material dilutive effect.

(c) *Selected Quarterly Information (Unaudited).* A summary of financial data for the quarterly periods indicated is as follows:

Quarterly Period Ended	Electric Revenues	Electric Operating Income	Net Income	Earnings per Share of Common Stock
	(Dollars in thousands except per share figures)			
March 31, 1978	$371,003	$74,775	$69,194	$0.87
June 30, 1978	309,548	49,379	48,034	0.52
September 30, 1978	362,826	52,984	52,455	0.55
December 31, 1978	353,343	59,863	60,918	0.67
March 31, 1979	402,927	77,008	80,814	0.94
June 30, 1979	329,485	54,344	59,590	0.58
September 30, 1979	374,089	55,215	64,826	0.65
December 31, 1979	386,056	67,310	69,530	0.71

Quarterly earnings generally fluctuate with seasonal weather conditions. In both 1978 and 1979, quarterly earnings also were affected by varying fuel expense resulting from changes in generation mix. Nuclear generation decreased and fossil-fueled generation increased during periods of refueling and maintenance of nuclear units. Effective January 1, 1979, the Company implemented an accounting procedure designed to match more closely fuel expense with the cost recovered through its North Carolina base rates for interim periods of a calendar year. The accounting procedure did not affect revenues or customer billings nor did it affect net income or earnings per share on a calendar year basis.

Quarterly revenues for the fourth quarter of 1978 and for 1979 reflect the impact of rate increases implemented in September 1978 and October 1979.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF THE STATEMENT OF EARNINGS

The following discussion presents management's analysis of the Statement of Earnings with respect to 1979 and 1978 as compared with the respective preceding year.

Electric Revenues and KWH Sales

Electric revenues increased 7% for 1979 primarily due to general rate increases implemented on September 1, 1978 and October 8, 1979 for all three of the Company's regulatory jurisdictions.

The 10% increase in electric revenues for 1978 is due mainly to rate increases implemented in 1978 along with higher KWH sales (including both a general basic increase in all three jurisdictions and numerous adjustments in revenues to reflect changing fuel costs). The interrelation of consumption (KWH usage), changes in basic rates and the change in fuel cost recovery, varying in all three jurisdictions, make it virtually impossible to segregate feasibly the effect of each of these factors.

While the average number of customers increased 2.7% in 1979 over 1978, KWH sales for that same period remained relatively constant due to mild weather and customers' conservation efforts. The 2.2% increase in KWH sales for 1978 was due principally to an increase in the total number of customers.

Fuel Used in Electric Generation

Fuel expense rose 8% in 1979 and 10% in 1978. The 1979 increase in fuel expense was due primarily to increased generation from fossil-fired plants. This was necessary to compensate for lower nuclear generation caused by outages related mainly to modifications required by the Nuclear Regulatory Commission. The increase in fuel expense during 1979 also reflected the continuing escalation in prices of all types of fuel used.

The increase in fuel prices was the major cause of the 10% increase in fuel expense in 1978. Improved nuclear KWH generation and an increase in purchased energy contributed to the decrease in fossil-fueled generation from the 1977 level resulting in an 8% decline in the tons of coal burned during 1978.

For information regarding the utilization of sources of generation and cost of fuels, see Item 1.—"Business—Fuel Supply".

Net Interchange and Purchased Power

Substantial power sales to other utilities occurred in 1979 contrasted with large power purchases from others in 1978. Most of the purchases in 1978 occurred during the third quarter to alleviate coal procurement problems caused by a railroad strike.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased 17% in 1979 and 11% in 1978 primarily because of inflation and compliance with more stringent regulatory requirements. Additional costs associated with the changing generation mix and increases in salaries, wages and benefits also contributed to such increased expenses.

Maintenance expenses increased 20% for 1979 primarily due to higher nuclear plant and equipment maintenance coupled with increased steam and overhead distribution maintenance. The 27% increase in 1978 was attributable to specific equipment repairs to all categories of generating stations and increased maintenance requirements on the Company's overhead power lines and rights-of-way.

Tax Expense

General taxes increased 9% in both 1979 and 1978, reflecting revenue growth which produced greater gross receipts taxes and increased payroll taxes resulting from an increase in the effective tax rates, a greater number of employees and higher average compensation levels. The 1978 increase also was due to property tax increases attributable to increased electric plant in service.

Total income tax expense decreased 20% in 1979 primarily due to the decrease in the Federal statutory rate and a 10% decrease in pretax income. The 15% increase in total income tax expense for 1978 reflected higher operating income and the tax treatment of the gain on the sale of an interest in the Catawba Nuclear Station.

Other Income

Other income rose 28% in 1979 and 36% in 1978 principally from an increase in allowance for funds used during construction (ADC) attributable to greater investment in construction work in progress. No generating units or other major construction projects were placed in service in 1979 or 1978. (Also see "Interest Deductions—Allowance for borrowed funds used during construction (credit)".)

Earnings of subsidiaries for 1979 increased 14% due primarily to the sale by Crescent Land & Timber Corp. of lake front lots.

For 1979 and 1978, "Other, net (deduction)" and the related income taxes reflect gains from the sale of an interest in the Catawba Nuclear Station and reductions relating to a coal supply contract as described in note 10 of Notes to Financial Statements.

Interest Deductions and Preference and Preferred Dividends

To finance its continuing construction program, the Company issued additional securities, which resulted in combined increases for interest (principally for long-term debt) and preferred dividends of 10% for 1979 and 11% for 1978.

The Company understands that an issue has been raised in litigation to which it is not a party relating to ADC as reported by another public utility. In this litigation, it is alleged that actual earnings were not properly presented in that ADC was included as "Other Income" without an adequate explanation of this item, and that ADC is not in fact income as generally understood, but rather a projection of future earnings not reflecting any actual yield on assets or any revenue during any fiscal period and not in fact earned upon completion of construction. ADC, which is not an item of current cash income, is included in the financial statements of the Company in accordance with the applicable system of accounts and in accordance with generally accepted accounting principles. The court has granted summary judgment in favor of the defendants in this litigation and the plaintiff has appealed.

Item 3. *Properties.*

The map on page 17 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V—Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company. Information concerning leases is set forth in note 7 of Notes to Financial Statements.

For additional information concerning the properties of the Company, see Item 1.—"Construction Program—Facilities Under Construction" and "Business—Fuel Supply".

Item 4. *Parents and Subsidiaries.*

The Duke Endowment owned approximately 16% of the outstanding common stock of the Company at December 31, 1979. The Duke Endowment is a common law trust, administered by 15 Trustees, 14 of whom constitute all of the Trustees of The Doris Duke Trust, another common law trust, which owned approximately 3% of the outstanding common stock of the Company. One of the Trustees of The Duke Endowment and The Doris Duke Trust is also a director of the Company.

The Company owns 100% of the voting securities of all of its subsidiaries. All of such subsidiaries are accounted for on the Company's financial statements by the equity method and, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (see note 2 of Notes to Financial Statements).

Item 5. *Legal Proceedings.*

Reference is made to Item 1.—"Construction Program" for information relating to licensing proceedings before the Nuclear Regulatory Commission with respect to the Company's nuclear generating facilities under construction.

Reference is made to Item 1.—"Business—Rate Matters" regarding pending proceedings before the North Carolina Utilities Commission and The Public Service Commission of South Carolina.

Reference is made to Item 1.—"Business—Regulation—*Environmental Matters*" with respect to environmental proceedings involving the Company.

Reference is made to Item 1.—"Business—Regulation—*Nuclear Facilities*" for developments with respect to the Company's nuclear facilities.

Item 6. *Increases and Decreases in Outstanding Securities and Indebtedness.*

(a) Changes in outstanding equity securities:

Common stock, without par value:		
Shares outstanding at December 31, 1978		72,132,229
Shares issued in public offering on March 21, 1979	5,500,000	
Shares issued pursuant to Stock Purchase—Savings Program for Employees on various dates in 1979	819,308	
Shares issued pursuant to Dividend Reinvestment and Stock Purchase Plan on various dates in 1979	357,462	
Shares issued pursuant to Employees' Stock Ownership Plan on various dates in 1979	322,522	
Conversion of 88,405 shares of Preference Stock, 6¾% Convertible Series AA, $100 par, at $24.73 per share	357,418	7,356,710
Shares outstanding at December 31, 1979		79,488,939
Preference Stock, 6¾% Convertible Series AA, $100 par:		
Shares outstanding at December 31, 1978		424,467
Conversion of Preference Stock (see above)		88,405
Shares outstanding at December 31, 1979		336,062
Preferred Stock:		
Shares outstanding at December 31, 1978		7,750,000
Shares of 8.84% Preferred Stock, Series N, $100 par, issued in public offering on June 14, 1979		500,000
Shares outstanding at December 31, 1979		8,250,000

(b) Changes in outstanding debt securities and other debt:

Issuance of First and Refunding Mortgage Bonds, 10⅛% Series Due 2009	$150,000,000
Sinking fund retirement of First and Refunding Mortgage Bonds, 11% Series Due 1994	$ 6,750,000
Retirement of Term Notes, 13% Due 1979	$100,000,000
Establishment of nuclear fuel trust	$ 75,000,000

The information set forth under Item 5B in the Company's Form 10-Q for the quarter ended June 30, 1979 and the information set forth under Items 5 and 6 in the Company's Form 10-Q for the quarter ended September 30, 1979 are incorporated herein by reference.

(c) Changes in outstanding debt securities and other debt during the fourth quarter of the fiscal year.

First and Refunding Mortgage Bonds	
Amount Outstanding:	
September 30, 1979	$1,999,750,000
December 31, 1979	2,149,750,000
Issuance of First and Refunding Mortgage Bonds, 10⅛% Series B Due 2009	$ 150,000,000

On October 10, 1979, the Company issued and sold through competitive bidding $150,000,000 principal amount of its First and Refunding Mortgage Bonds, 10⅛% Series B Due 2009, at a price to the Company of 98.91% of their principal amount, to a group of underwriters jointly managed by The First Boston Corporation; Morgan Stanley & Co. Incorporated; Drexel Burnham Lambert Incorporated; E. F. Hutton & Company Inc.; Kidder, Peabody & Co. Incorporated; Lehman Brothers Kuhn Loeb Incorporated; Smith Barney, Harris Upham & Co. Incorporated; Wertheim & Co., Inc.; Dean Witter Reynolds Inc.; L. F. Rothschild, Unterberg, Towbin, and Donaldson, Lufkin & Jenrette Securities Corporation. The aggregate net cash proceeds were $148,365,000 after underwriting discounts. Such sale resulted in other expenses of approximately $244,000 at December 31, 1979.

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The proceeds from the sale of the First and Refunding Mortgage Bonds, 10¼% Series B Due 2009, were used for the purpose of financing the construction of additions to the Company's electric plant facilities, the acquisition of nuclear fuel and the payment of maturing long-term debt, principally by the payment of short-term obligations incurred primarily for those purposes.

The First and Refunding Mortgage Bonds, 10¼% Series B Due 2009, were registered under a Registration Statement on Form S-7 (File No. 2-65371) which became effective for selling purposes on October 2, 1979.

Item 7. *Changes in Securities and Changes in Security for Registered Securities.*

Not applicable.

Item 8. *Defaults upon Senior Securities.*

Not applicable.

Item 9. *Approximate Number of Equity Security Holders.*

Title of Class	Number of Record Holders at February 15, 1980
Common Stock—Without Par Value	106,732
Preference Stock, $100 Par, 6¾% Convertible Series AA	1,858
Preferred Stock, $100 Par, 4.50% Series C	100
Preferred Stock, $100 Par, 5.72% Series D	725
Preferred Stock, $100 Par, 6.72% Series E	608
Preferred Stock, $100 Par, 8.70% Series F	3,906
Preferred Stock, $100 Par, 8.20% Series G	3,874
Preferred Stock, $100 Par, 7.80% Series H	1,631
Preferred Stock, $100 Par, 7.35% Series I	1
Preferred Stock, $100 Par, 8.20% Series J	5
Preferred Stock, $100 Par, 8.28% Series K	358
Preferred Stock, $100 Par, 8.375% Series L	6
Preferred Stock, $100 Par, 8.84% Series M	234
Preferred Stock, $100 Par, 8.84% Series N	83
Preferred Stock A, $25 Par, 10.76% Series 1975	7,235

Item 10. *Submission of Matters to a Vote of Security Holders.*

Not applicable.

Item 11. *Indemnification of Directors and Officers.*

Reference is made to Item 9 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1975.

Item 12. *Financial Statements, Exhibits Filed and Reports on Form 8-K.*

(a)1. Financial Statements

The financial statements, including supporting schedules, are listed in the Index to Financial Statements and Schedules on page 28, filed as a part of this Annual Report.

2. Exhibits

I. Computation of Fully Diluted Earnings Per Share.

II. Annual Report on Form 11-K with respect to the Stock Purchase-Savings Program for Employees of the Company for the fiscal year ended October 31, 1979 and the Employees' Stock Ownership Plan for the fiscal year ended December 31, 1979.

(b) Reports on Form 8-K

There were no reports on Form 8-K filed during the last quarter of 1979.

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age*
Carl Horn, Jr.**	Chairman of the Board and Chief Executive Officer	1976	58
W. S. Lee**	President and Chief Operating Officer, and Director	1978	50
D. W. Booth**	Executive Vice President and Director	1976	55
W. H. Grigg**	Senior Vice President, Legal and Finance, and Director	1971	47
A. C. Thies**	Senior Vice President, Production and Transmission, and Director	1971	58
John D. Hicks**	Senior Vice President, Public Affairs, and Director	1971	56
W. H. Owen**	Senior Vice President, Engineering and Construction, and Director	1978	53
Keith Arledge	Vice President, Western Division	1973	62
Thomas C. Berry	Vice President, Southern Division	1976	49
J. Wesley Lewis	Vice President, Division Operations	1973	64
L. C. Dail	Vice President, Design Engineering	1978	54
Donald H. Denton, Jr.	Vice President, Marketing	1975	42
Robert L. Dick	Vice President, Construction	1971	52
Steve C. Griffith, Jr.	Vice President and General Counsel	1977	46
M. T. Hatley, Jr.	Vice President, Rates	1979	57
Porter A. Hauser	Vice President, Finance Administration	1976	62
E. N. Hedgepeth, Jr.	Vice President, Distribution Engineering, Construction and Operations	1978	52
Frank A. Jenkins	Vice President, Transmission	1971	60
S. T. Lattimore	Vice President, Computer Services	1979	53
Joe S. Major, Jr.	Vice President, Personnel	1971	59
Joseph G. Mann	Vice President, Northern Division	1973	56
Paul H. Mann, Jr.	Vice President, Operation	1978	57
Henry L. Cranford	Vice President, Central Division	1980	52
William O. Parker, Jr.	Vice President, Steam Production	1974	55
Thomas M. Patrick, Jr.	Vice President, Eastern Division	1973	59
Richard R. Pierce	Vice President, Corporate Communications	1979	57
William R. Stimart	Vice President, Regulatory Affairs	1979	48
James W. White	Vice President, General Services	1979	54
George W. Ferguson, Jr.	Secretary and Deputy General Counsel	1975	47
Richard C. Ranson	Treasurer	1976	38

* As of March 1980.

** Members of the Executive Committee.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

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PART II

Part II is omitted in accordance with General Instruction H of Form 10-K since the Company has filed with the Securities and Exchange Commission a definitive proxy statement pursuant to Regulation 14A. Information concerning executive officers of the Company appears on page 26 of this Annual Report.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned thereunto duly authorized.

DUKE POWER COMPANY
(Registrant)

By W. H. GRIGG
W. H. Grigg, Senior Vice President,
Legal and Finance

March 28, 1980

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DUKE POWER COMPANY

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All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

Financial statements and schedules of the Company's subsidiaries are omitted because all such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management is responsible for all the information contained in the financial statements and other sections of this Annual Report. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions that should be included, and the other information in this Annual Report is consistent with those statements. In preparing the financial statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. The Company's accounting controls provide reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected by employees within a timely period in the normal course of performing their assigned functions. The Board of Directors pursues its oversight role for these financial statements through the audit committee, which is composed solely of directors who are not officers or employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each and to monitor the discharge by each of their responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte Haskins & Sells, who have free access to the audit committee or the Board, without management present, to discuss internal accounting control, auditing and financial reporting matters.

The independent auditors are engaged to express an opinion on the financial statements. Their examination is conducted in accordance with generally accepted auditing standards and includes a review of internal controls and a test of transactions to the extent necessary to allow them to report on the fairness of the operating results and financial condition of the Company.

AUDITORS' OPINION

Duke Power Company:

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

In our opinion, the accompanying balance sheets and statements of capitalization, earnings, retained earnings, and source of funds for plant construction costs present fairly the financial position of the Company at December 31, 1978 and 1979 and the results of its operations and the source of its funds for plant construction costs for each of the five years in the period ended December 31, 1979, in conformity with generally accepted accounting principles applied on a consistent basis; and the supplemental schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 11, 1980

DE00000403

DUKE POWER COMPANY

BALANCE SHEET

(Dollars in Thousands)

ASSETS

	December 31	
	1978	1979
Electric Plant—at original cost (notes 1, 3 and 7) (schedules V and VI)		
Electric plant in service	$3,964,825	$4,126,513
Less accumulated depreciation and amortization	1,239,250	1,399,032
Electric plant in service, net	2,725,575	2,727,481
Construction work in progress	1,844,323	2,481,957
Total electric plant, net	4,569,898	5,209,438
Other Property and Investments		
Other property—at cost (less accumulated depreciation: 1978—$4,835; 1979—$5,216) (schedules V and VI)	21,623	22,267
Investments in and advances to subsidiaries (note 2)	23,558	18,412
Other investments—at cost or less	8,759	8,809
Total other property and investments	53,940	49,488
Current Assets		
Cash (including time deposits: 1978—$17,866; 1979—$1,282) (note 9)	20,794	4,833
Short-term U.S. Government securities	17,000	—
Receivables (less allowance for losses: 1978—$3,608; 1979—$4,131) (schedule XII)	119,596	142,751
Materials and supplies—at average cost		
Coal	122,586	130,889
Other	61,062	67,800
Total current assets	341,038	346,273
Deferred Debits		
Debt expense, being amortized over terms of related debt	11,926	13,635
Other	7,819	7,241
Total deferred debits	19,745	20,876
Total assets	$4,984,621	$5,626,075

See notes to financial statements.

DUKE POWER COMPANY

BALANCE SHEET

(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	December 31	
	1978	1979
Capitalization (see Statement of Capitalization)		
Common stock equity	$1,537,201	$1,758,016
Preference and preferred stocks without sinking fund requirements	417,447	408,606
Preferred stocks with sinking fund requirements	220,000	268,500
Long-term debt	1,974,209	2,341,855
Total capitalization	4,148,857	4,776,977
Current Liabilities		
Accounts payable	112,568	94,191
Interest accrued	53,366	55,501
Taxes accrued	68,993	41,286
Other	9,946	11,301
Total	244,873	202,279
Notes payable for construction—pending permanent financing (note 9)	—	112,000
Current maturities of long-term debt and preferred stock	149,107	10,603
Total current liabilities	393,980	324,882
Accumulated Deferred Income Taxes (notes 1 and 8)	313,058	341,650
Deferred Credits		
Investment tax credit (notes 1 and 8)	111,661	162,945
Other (schedule XII)	17,065	19,621
Total deferred credits	128,726	182,566
Commitments and Contingencies (notes 7 and 11)		
Total capitalization and liabilities	$4,984,621	$5,626,075

See notes to financial statements.

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DUKE POWER COMPANY

STATEMENT OF CAPITALIZATION

(Dollars in Thousands)

	December 31	
	1978	1979
Common Stock Equity (notes 2 and 4)		
Common stock	$1,271,028	$1,414,791
Retained earnings	266,173	343,225
Total common stock equity	1,537,201	1,758,016
Preference and Preferred Stocks Without Sinking Fund Requirements (note 5)		
Preference stock	42,447	33,606
Preferred stock	375,000	375,000
Total preference and preferred stocks without sinking fund requirements	417,447	408,606
Preferred Stocks With Sinking Fund Requirements (note 6)		
Preferred stock	160,000	210,000
Preferred stock A	60,000	60,000
	220,000	270,000
Preferred stock A, current sinking fund requirement	—	(1,500)
Total preferred stocks with sinking fund requirements	220,000	268,500
Long-Term Debt (note 3)		
First and refunding mortgage bonds	1,896,500	2,149,750
Sinking fund debentures—4¼%, due 1982	25,000	25,000
Term notes—13%, due 1979	100,000	—
Pollution control obligations—75% of prime rate, due 1983	2,500	2,500
Capitalized leases (note 7)	24,951	22,829
Nuclear fuel trusts	50,000	125,000
Turbine generator leases (note 7)	25,535	28,762
Unamortized debt discount and premium, net	(1,170)	(2,883)
Current maturities of long-term debt	(149,107)	(9,103)
Total long-term debt	1,974,209	2,341,855
Total capitalization	$4,148,857	$4,776,977

See notes to financial statements.

DUKE POWER COMPANY

STATEMENT OF RETAINED EARNINGS

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Balance—Beginning of year	$109,037	$114,521	$161,610	$207,897	$266,173
Add—Net income	117,143	173,701	192,349	230,601	274,760
Total	226,180	288,222	353,959	438,498	540,933
Deduct					
Dividends accrued					
Common stock	70,949	87,833	103,755	121,961	141,035
Preference stock—6¾%, Convertible Series AA	3,375	3,375	3,375	3,184	2,564
Preferred stock (annual rates indicated)					
Series C ($4.50)	1,575	1,575	1,575	1,575	1,575
Series D ($5.72)	2,002	2,002	2,002	2,002	2,002
Series E ($6.72)	2,352	2,352	2,352	2,352	2,352
Series F ($8.70)	5,220	5,220	5,220	5,220	5,220
Series G ($8.20)	4,920	4,920	4,920	4,920	4,920
Series H ($7.80)	4,680	4,680	4,680	4,680	4,680
Series I ($7.35)	4,410	4,410	4,410	4,410	4,410
Series J ($8.20)	—	—	2,659	4,100	4,100
Series K ($8.28)	—	—	1,230	4,140	4,140
Series L ($8.375)	—	—	—	2,268	4,188
Series M ($8.84)	—	—	—	1,325	3,536
Series N ($8.84)	—	—	—	—	2,419
Preferred Stock A—10.76%, 1975 Series	5,810	6,456	6,456	6,456	6,456
Capital stock expense	6,366	3,789	3,428	3,732	4,111
Total deductions	111,659	126,612	146,062	172,325	197,708
Balance—End of year	$114,521	$161,610	$207,897	$266,173	$343,225
Common dividends per share	$1.40	$1.525	$1.63	$1.74	$1.83

See notes to financial statements.

DUKE POWER COMPANY

STATEMENT OF SOURCE OF FUNDS FOR PLANT CONSTRUCTION COSTS

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Funds from operations					
Net income	$117,143	$173,701	$192,349	$230,601	$274,760
Non-fund items					
Depreciation and nuclear fuel amortization	110,327	118,646	134,048	170,373	190,110
Deferred income taxes and investment tax credit, net of amortization	50,802	107,019	85,347	89,786	91,991
Total equity component of the allowance for funds used during construction	—	—	(62,441)	(87,810)	(121,701)
Common equity component of the allowance for funds used during construction	(25,331)	(29,702)	—	—	—
Other, net	4,073	(1,259)	(4,760)	(2,669)	(5,854)
Funds from operations	257,014	368,405	344,537	400,281	429,306
Dividends paid on common stock	(70,949)	(87,833)	(103,755)	(121,961)	(141,035)
Dividends paid on preference and preferred stocks	(34,075)	(34,900)	(38,535)	(46,312)	(52,550)
Funds retained in the business	151,990	245,582	202,247	232,008	235,721
Funds from financing and sale of assets—net proceeds					
Sale of an interest in the Catawba Nuclear Station	—	—	—	260,047	—
First mortgage bonds	203,632	118,329	123,056	123,249	295,768
Pollution control obligations	—	2,364	—	80	—
Common stock	75,188	97,429	129,768	124,667	131,561
Preferred stock	57,450	—	99,874	89,674	49,251
Sale and sale/leaseback transactions	61,429	17,443	—	—	—
Nuclear fuel trusts	—	—	1,000	48,953	76,254
Increase (decrease) in notes payable for construction	(57,049)	(59,043)	148,095	(174,095)	112,000
Retirement of long-term debt	(87,225)	(30,938)	(79,646)	(71,405)	(150,412)
Funds from financing and sale of assets	253,425	145,584	422,347	401,170	514,422
Total available funds	405,415	391,166	624,394	633,178	750,143
Working capital requirements (increase) decrease	8,206	54,380	(42,220)	11,330	(43,536)
Plant construction expenditures	413,621	445,546	582,174	644,508	706,607
Total equity component of the allowance for funds used during construction	—	—	62,441	87,810	121,701
Common equity component of the allowance for funds used during construction	25,331	29,702	—	—	—
Plant construction costs (including nuclear fuel)	$438,952	$475,248	$644,615	$732,318	$828,308

See notes to financial statements.

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DUKE POWER COMPANY

NOTES TO FINANCIAL STATEMENTS

For the Five Years Ended December 31, 1979

1. Significant Accounting Policies

Additions to Electric Plant. The Company capitalizes all construction-related direct labor and materials, as well as related indirect construction costs, including general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of repairs and replacements representing less than a unit of property is charged to electric expenses; the cost of renewals and betterments of units of property is capitalized. The original cost of property retired, together with removal costs less salvage, is charged to accumulated depreciation.

Allowance for Funds Used During Construction (ADC). ADC is an accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are transferred from the statement of income to construction work in progress in the balance sheet and, accordingly, are capitalized in the same manner as construction labor and material costs. This item is recognized as a cost of "Electric Plant", with offsetting credits to "Other Income" and "Interest Deductions", because, under established regulatory rate practices, a utility is permitted to include a fair return on, and the recovery of, these capital costs through their inclusion in rate base and in the provision for depreciation.

Effective January 1, 1977, the Federal Power Commission (now the Federal Energy Regulatory Commission) revised the Uniform System of Accounts to specify a formula for the determination of the maximum rate for computing ADC. The formula is based on embedded cost and permits compounding. This revision also prescribed the financial statement presentation of ADC which now consists of the "Allowance for equity funds used during construction" included in "Other Income" plus the "Allowance for borrowed funds used during construction" shown as a credit in "Interest Deductions". In conformity with such revision, the Company changed its presentation of ADC in the statement of source of funds for plant construction costs. The new formula for determining the amount of ADC did not have a significant impact on financial statements subsequent to 1976. The Company believes it would be inappropriate to reclassify the amounts of ADC for the periods prior to January 1, 1977 in the statement of income as this would imply that the prior periods were comparable when, in fact, prior to such date separate components were not required to be determined for the cost of borrowed funds and the cost of other funds.

The amount of ADC transferred in the five years ended December 31, 1979 has changed as the balance of construction work in progress has fluctuated and as interest rates and equity capital costs have increased. ADC has been calculated using current cost rates, net of applicable income taxes, of 8% for 1975 and 1976 and an average embedded rate of 6.92% for 1977, 7.13% for 1978 and 8.01% for 1979 calculated under the new formula with semiannual compounding. If it is assumed that the principal funds used to finance construction during 1975 and 1976 were obtained 28% and 29% from common equity, 56% and 54% from debt at current costs net of income taxes and 13% for both years from preference and preferred stocks at current costs, the common equity component of ADC as related to earnings for common stock would have amounted to 31% and 21% for 1975 and 1976, respectively. Earnings resulting from the common equity component of ADC are related principally to the additional capital obtained through the issuance of common stock.

North Carolina statutes require that capital expenditures for construction work in progress (CWIP), incurred after July 1, 1979 and requested in rate applications after such date, be included in rate base for ratemaking purposes. Under such statutes, utilities are permitted to continue capitalizing ADC with respect to CWIP not included in rate base but are not permitted to do so with respect to CWIP included in rate base. As of December 31, 1979, the Company had not filed any rate applications which included CWIP in rate base.

Depreciation and Amortization. Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted average depreciation rates ranged from 3.26% to 3.33% during the five years ended December 31, 1979. All steam generator units are depreciated at the rate of 3.57%

(28-year life, net). Beginning October 1979, the depreciation rate on nuclear plant was revised from 3.57% to 4.00% consistent with recent regulatory approval. The Company is continuing to evaluate the impact of nuclear plant decommissioning costs.

Provisions for amortization of nuclear fuel, which are included in "Fuel used in electric generation", are recorded using the unit of production method. Nuclear fuel amortization includes an estimate of the net salvage value or removal costs. For fuel burned since July 1, 1977, a net removal charge has been included in such amortization in view of the present unavailability of reprocessing facilities. The estimated disposal costs for fuel burned prior to such date are being amortized currently over 10 years.

Income Taxes. The Company and its subsidiaries file a consolidated Federal income tax return. Income taxes are allocated to each company based on its taxable income or loss.

The Company's income taxes are allocated to electric operating expense and to non-electric operations under "Other Income". The "Income taxes—credit" classified under "Other Income" results from tax deductions of interest costs relating to investments in non-utility properties, mainly construction work in progress.

The Company provides deferred income taxes under normalization accounting for timing differences between book and tax income, principally resulting from accelerated tax depreciation, capitalized taxes and employee benefits, repair allowance and cost of removal, and nuclear fuel disposal costs.

Investment tax credit is being deferred and amortized over the depreciable lives of the related properties. At December 31, 1979, the Company had unused investment tax credit amounting to approximately $75,000,000 which will be available for use through 1986.

Retirement Plan Cost. The Company has a non-contributory retirement plan for the benefit of its employees. The Company's policy is to fund pension costs accrued, which amounted to $6,493,000 for 1975, $11,788,000 for 1976, $16,931,000 for 1977, $20,053,000 for 1978 and $23,844,000 for 1979.

The plan was amended, effective September 1, 1975, to provide increased participation and benefits. The total unfunded prior service costs of the plan amounted to approximately $19,559,000 at December 31, 1979 which generally are being amortized over 20 years.

The actuarially computed value of vested benefits under the plan exceeded the assets of the plan by approximately $11,169,000 according to the latest available actuarial report.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel costs. Procedures for both North Carolina and South Carolina retail jurisdictions provide for periodic review of fuel costs with provisions for changing such costs in base rates. With respect to South Carolina, the Company continues to reflect in revenues the difference between actual fuel costs incurred and fuel costs recovered through base rates. Procedures for the wholesale jurisdiction provide for monthly fuel cost adjustments.

2. Subsidiaries

The Company has five wholly-owned operating subsidiaries. Mill-Power Supply Company is a wholesale jobber and distributor of electrical supplies and equipment and acts as purchasing agent for the Company. Crescent Land & Timber Corp. is a land management and forestry company, whose principal holdings are non-utility land acquired from the Company. Eastover Mining Company mines coal for the Company (supplying 14% of its requirements for 1979) on properties owned or leased by Eastover Land Company, the Company's mineral holding subsidiary. Western Fuel, Inc. is involved in the exploration and development of uranium ore deposits in central Wyoming.

The Company follows the equity method of accounting for such subsidiaries. Retained earnings include $24,672,000 of undistributed earnings of subsidiaries at December 31, 1979. Cash dividends received from subsidiaries were $1,600,000 in 1976, $850,000 in 1977, $2,600,000 in 1978 and $5,800,000 in 1979.

3. Long-Term Debt

First and Refunding Mortgage Bonds outstanding at December 31, 1978 and December 31, 1979 were as follows (dollars in thousands):

Series	Year Due	1978	1979	Series	Year Due	1978	1979
2⅛%.....	1979	$ 40,000	$ —	7⅛% B.....	2001	$ 40,000	$ 40,000
3¼%.....	1981	35,000	35,000	7¼%.....	2002	100,000	100,000
3⅛%.....	1986	30,000	30,000	7¼% B.....	2002	75,000	75,000
4½%.....	1992	50,000	50,000	7¼%.....	2003	100,000	100,000
4¼% B.....	1992	50,000	50,000	8¼% B.....	2003	100,000	100,000
4½%.....	1995	40,000	40,000	9¼%.....	2004	100,000	100,000
5⅛%.....	1997	75,000	75,000	9½%.....	2005	100,000	100,000
6¼%.....	1998	75,000	75,000	11%.....	1994	111,500	104,750
7%.....	1999	75,000	75,000	8¼%.....	2006	100,000	100,000
8% B.....	1999	75,000	75,000	8¼%.....	2007	125,000	125,000
8½%.....	2000	75,000	75,000	9¼%.....	2008	125,000	125,000
8⅛% B.....	2000	100,000	100,000	10¼%.....	2009	—	150,000
7½%.....	2001	100,000	100,000	10¼% B.....	2009	—	150,000
				Total.....		$1,896,500	$2,149,750

Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds which does not specify any authorized amount of Bonds, issuance being limited by property additions, earnings and other provisions of such Indenture. The Indenture relating to the 4⅛% Sinking Fund Debentures due September 1, 1982 limits such issue to its presently outstanding principal amount.

The sinking fund provisions of the First and Refunding Mortgage Bonds, 11% Series Due 1994, require the annual retirement of $6,750,000 of such Bonds.

The annual amounts of long-term debt maturities (including sinking fund requirements and capitalized lease principal payments) through 1984 are $9,103,000 in 1980, $44,129,000 in 1981, $35,046,000 in 1982, $11,921,000 in 1983 and $9,664,000 in 1984.

The Company has $125,000,000 in outstanding obligations under two nuclear fuel trusts. Based on estimated nuclear fuel consumption, the approximate maturities through 1982 are $35,000,000 in 1980 and $45,000,000 in 1981 and 1982. The Company intends to transfer title to additional nuclear fuel to the trusts to replace such amounts as fuel is consumed.

4. Common Stock and Retained Earnings

There were 100,000,000 shares of common stock, without par value, authorized at December 31, 1978 and December 31, 1979, of which 72,132,229 shares and 79,488,939 shares were outstanding at December 31, 1978 and December 31, 1979, respectively.

At December 31, 1979, certain shares of common stock were reserved for issuance as follows:

	Shares
Conversion of the Preference Stock, 6¼% Convertible Series AA	1,358,924
Stock Purchase-Savings Program for Employees	2,594,803
Dividend Reinvestment and Stock Purchase Plan	596,217
Employees' Stock Ownership Plan	638,886
Total	5,188,830

Issues of shares of common stock for the five years ended December 31, 1979 were as follows:

	Year Ended December 31				
	1975	1976	1977	1978	1979
Public sales	5,000,000	5,000,000	5,500,000	5,500,000	5,500,000
Stock Purchase-Savings Program for Employees	504,241	418,563	443,471	623,141	819,308
Dividend Reinvestment and Stock Purchase Plan	180,968	179,807	191,781	260,912	357,462
Employees' Stock Ownership Plan	—	59,864	114,632	14,096	322,522
Conversion of Preference Stock	—	—	586	304,108	357,418
Total	5,685,209	5,658,234	6,250,470	6,702,257	7,356,710

The Indenture relating to the 4¼% Sinking Fund Debentures due September 1, 1982 provides, among other things, for certain restrictions on the payment of cash dividends. Under the terms of such Indenture, none of the Company's retained earnings as of December 31, 1979 was restricted with respect to the declaration or payment of dividends.

5. Preference and Preferred Stocks Without Sinking Fund Requirements

At December 31, 1978 and December 31, 1979, there were 10,000,000 shares of Preferred Stock authorized which were issuable with or without sinking fund requirements. At December 31, 1978 and December 31, 1979, there were 3,750,000 shares outstanding without sinking fund requirements. In addition, there were 1,500,000 shares of Preference Stock authorized at December 31, 1978 and December 31, 1979, of which 424,467 shares and 336,062 shares were outstanding at December 31, 1978 and December 31, 1979, respectively.

Preference and preferred stocks without sinking fund requirements at December 31, 1978 and December 31, 1979 were as follows:

			Redemption Price Per Share			Amount	
Rate/Series	Par Value	Year Issued	Current	Eventual Minimum	Shares Outstanding	1978	1979
						(Dollars in Thousands)	
6¼%, AA Convertible	$100	1969	$100.00	$100.00	336,062	$ —	$ 33,606
					424,467	42,447	—
4.50%C	100	1964	101.00	101.00	350,000	35,000	35,000
5.72%D	100	1966	103.00	101.00	350,000	35,000	35,000
6.72%E	100	1968	107.00	102.00	350,000	35,000	35,000
8.70%F	100	1970	110.00*	101.00	600,000	60,000	60,000
8.20%G	100	1971	107.00	101.00	600,000	60,000	60,000
7.80%H	100	1972	107.42	103.52	600,000	60,000	60,000
8.28%K	100	1977	109.63*	101.35	500,000	50,000	50,000
8.84%M	100	1978	109.87*	101.03	400,000	40,000	40,000
				Total		$417,447	$408,606

The outstanding Preference Stock, 6¼% Convertible Series AA, is convertible into shares of common stock at the adjusted conversion price of $24.73 per share, each share of such Preference Stock being taken at $100 for such purpose. The conversion price is subject to certain adjustments designed to protect the conversion privilege against dilution.

* Redemption subject to certain restrictions regarding refunding operations.

6. Preferred Stocks With Sinking Fund Requirements

At December 31, 1978 and December 31, 1979, there were 10,000,000 shares of Preferred Stock authorized which were issuable with or without sinking fund requirements. At December 31, 1978 and December 31, 1979, there were outstanding 1,600,000 shares and 2,100,000 shares, respectively, with sinking fund requirements. In addition, there were 10,000,000 shares of Preferred Stock A authorized at December 31, 1978 and December 31, 1979, of which 2,400,000 shares were outstanding at December 31, 1978 and December 31, 1979.

The 7.35% Preferred Stock, Series I, provides for a sinking fund for the annual redemption of 24,000 shares at $100 per share on a cumulative basis beginning March 16, 1984. The Company may at its option, on a non-cumulative basis, redeem an additional 24,000 shares annually at $100 per share beginning March 16, 1984; such redemption option is limited to an aggregate of 200,000 shares.

The 8.20% Preferred Stock, Series J, provides for a sinking fund for the annual redemption of 20,000 shares at $100 per share on a cumulative basis beginning June 16, 1982. The Company may at its option, on a non-cumulative basis, redeem an additional 20,000 shares annually at $100 per share beginning June 16, 1982; such redemption option is limited to an aggregate of 175,000 shares.

The 8.375% Preferred Stock, Series L, provides for a sinking fund for the annual redemption of 20,000 shares at $100 per share on a cumulative basis beginning June 16, 1983. The Company may at its option, on a non-cumulative basis, redeem an additional 20,000 shares annually at $100 per share beginning June 16, 1983; such redemption option is limited to an aggregate of 166,666 shares.

The 8.84% Preferred Stock, Series N, provides for a sinking fund for the annual redemption of 16,250 shares at $100 per share on a cumulative basis beginning June 16, 1984. The Company may at its option, on a non-cumulative basis, redeem an additional 16,250 shares annually at $100 per share beginning June 16, 1984.

The 10.76% Preferred Stock A, 1975 Series, provides for a sinking fund for the annual redemption of 60,000 shares at $25 per share on a cumulative basis beginning March 16, 1980. The Company may at its option, on a non-cumulative basis, redeem an additional 60,000 shares annually at $25 per share beginning March 16, 1980.

Preferred stocks with sinking fund requirements at December 31, 1978 and December 31, 1979 were as follows:

			Redemption Price Per Share			Amount	
Rate/Series	Par Value	Year Issued	Current	Eventual Minimum	Shares Outstanding	1978	1979
						(Dollars in Thousands)	
7.35%I	$100	1973	$110.00	$101.00	600,000	$ 60,000	$ 60,000
8.20%J	100	1977	110.00*	102.00	500,000	50,000	50,000
8.375%L	100	1978	108.38*	100.00	500,000	50,000	50,000
8.84%N	100	1979	108.84*	100.00	500,000	—	50,000
10.76%A	25	1975	27.69*	25.25	2,400,000	60,000	60,000
				Total		$220,000	$270,000

The annual amounts of sinking fund requirements through 1984 are $1,500,000 in 1980 and 1981, $3,500,000 in 1982, $5,500,000 in 1983 and $9,525,000 in 1984.

On February 6, 1980, the Company agreed to sell 500,000 shares of 11% Preferred Stock, Series O, for $50,000,000 for delivery on February 14, 1980.

* Redemption subject to certain restrictions regarding refunding operations.

7. Leases

Rentals incurred during the five-year period 1975-1979 and rental commitments at December 31, 1979 under financing leases not capitalized and operating leases were as follows:

	Financing Leases Not Capitalized	Operating Leases	Total
	(Dollars in Thousands)		
Rentals Incurred:			
1975	$ 36,003	$ 2,060	$ 38,063
1976	36,009	1,534	37,543
1977	29,912	1,912	31,824
1978	21,786	2,015	23,801
1979	12,234	2,810	15,044
Rental Commitments:			
1980	11,876	3,049	14,925
1981	11,795	3,097	14,892
1982	11,649	2,847	14,496
1983	11,510	2,741	14,251
1984	11,330	2,838	14,168
Later years	79,959	19,086	99,045

Rentals charged to operating expenses were $34,593,000 in 1975, $34,629,000 in 1976, $29,248,000 in 1977, $21,098,000 in 1978 and $11,950,000 in 1979.

Substantially all leases require the Company to pay taxes and operation and maintenance expenses. Rentals incurred and rental commitments under combustion turbine generator leases include accruals in excess of current payments in amounts required to equalize annual rent expense and satisfy the obligations of the leases, net of salvage, at the end of the estimated useful life of the generators. Such leases contain options to purchase beginning in 1981 at the lessors' unrecovered cost. Other leases generally contain options to purchase at the lessors' unrecovered cost or fair market value.

Obligations under capitalized leases are included in long-term debt. Certain of the Company's financing leases have been treated as operating leases. Had the Company capitalized its remaining financing leases, the original cost of "Electric plant in service" and "Long-term debt" would have increased as follows:

	1978	1979
	(Dollars in Thousands)	
Electric plant in service	$114,800	$95,131
Capitalized leases	$ 66,200	$61,174
Less current maturities	1,500	1,194
Long-term debt	$ 64,700	$59,980

The effect of such capitalization on net income would not have been material for any of the five years ended December 31, 1979.

8. Income Tax Expense

Income tax expense consisted of the following:

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Electric Expenses					
Current income taxes					
Federal	$36,361	$ 25,927	$ 37,122	$ 42,187	$ 61,698
State	5,379	10,978	9,278	11,279	14,581
	41,740*	36,905*	46,400*	53,466*	76,278*
Deferred taxes, net**					
Excess tax over book depreciation	42,756	41,443	38,127	33,770	27,594
Capitalized taxes, employee benefits, etc.	4,361	9,482	12,465	13,720	16,545
Repair allowance and cost of removal	4,091	4,699	7,434	6,153	7,369
Nuclear fuel disposal costs	—	—	—	(9,610)	(10,800)
	51,208	55,624	58,026	44,033	40,708
Investment tax credit					
Deferred	—	53,372	28,949	45,467	41,196
Amortization of deferments (credit)	(406)	(1,977)	(1,618)	(2,540)	(4,678)
	(406)	51,395	27,331	42,927	36,518
Total electric expenses	92,542	143,924	131,757	140,426	153,504
Other Income					
Income taxes—other, net	(930)	(640)	(778)	16,963	(16,320)
Income taxes—credit					
Federal	(18,411)	(19,703)	(22,518)	(31,532)	(35,528)
State	(2,448)	(2,620)	(2,995)	(4,193)	(4,930)
Total other income	(21,789)*	(22,963)*	(26,291)*	(18,762)*	(56,778)*
Total income tax expense	$70,753	$120,961	$105,466	$121,664	$ 96,726

* Net taxes payable amounted to $19,951,000, $13,942,000, $20,109,000, $34,704,000 and $19,500,000 for 1975, 1976, 1977, 1978 and 1979, respectively.

** "Deferred taxes, net" included state income taxes of $5,511,000 for 1975, $6,406,000 for 1976, $6,489,000 for 1977, $4,521,000 for 1978 and $4,399,000 for 1979.

Income taxes differed from amounts computed by applying the statutory tax rate to pretax income as follows:

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Income taxes on pretax income at the statutory Federal rate of 48% for 1975-1978 and 46% for 1979	$90,190	$141,438	$142,951	$169,087	$170,884
Increase (reduction) in tax resulting from:					
Allowance for all funds used during construction (ADC)	(26,301)	(29,628)	(41,681)	(58,546)	(75,020)
Amortization of investment tax credit deferrals	(406)	(1,977)	(1,618)	(2,540)	(4,688)
Amortization of nuclear fuel book-tax basis difference (principally ADC)	1,845	1,568	1,382	1,363	1,177
Excess of tax gain over book profit on sale of assets (principally ADC)	—	—	—	5,647	—
State income taxes, net of Federal income tax benefit	4,333	7,638	6,595	7,801	7,483
Other items, net	1,092	1,922	(2,163)	(1,148)	(3,110)
Total income tax expense (see above)	$70,753	$120,961	$105,466	$121,664	$ 96,726

9. Short-Term Borrowings

The Company has lines of credit with 78 commercial banks and uses these lines, plus the sale of commercial paper, to finance its current cash requirements (bank loans normally are for 90 days or less). The Company also has revolving credit agreements with four commercial banks which run to December 1981, against which no borrowings have been made through 1979.

At December 31, 1979, $252,150,000 of the lines of credit and all of the revolving credit agreements were on a fee basis. The remaining lines of credit of $27,850,000 required average annual compensating balances of approximately $3,523,000. Borrowings are principally at the lending bank's commercial prime interest rate. Certain of the Company's bank line arrangements may require additional balances of 10% of the borrowings on an annual average.

A summary of short-term borrowings and credit arrangements follows:

	1978	1979
	(Dollars in Thousands)	
Amount outstanding at end of year:		
Commercial paper—average rate of 13.75%	—	$ 87,000
Bank loans—15.25% (prime rate)	—	$ 25,000
Maximum amount outstanding during the year	$175,295	$125,400
Average amount outstanding during the year	$ 61,695	$ 33,894
Weighted average interest rate for the year—computed on a daily basis	7.68%	11.93%
Lines of credit at end of year	$280,000	$280,000
Revolving credit agreements at end of year	—	$100,000

10. Other Income

In 1978, the Company sold a 75% interest in Unit No. 2 of the Catawba Nuclear Station and 37½% of its support facilities to the North Carolina Municipal Power Agency Number 1 representing certain North Carolina municipal customers. A net of tax profit of approximately $11,242,000 from the sale has been included in "Other Income". Income taxes of $24,927,000 related to the transaction reflect a taxable gain in excess of book gain, resulting principally from the treatment of ADC. At December 31, 1979, "Construction work in progress" included $607,826,000 representing the Company's investment in its

remaining interest in the Catawba Nuclear Station. Net profits included in progress payments made by such Agency as the Company completes construction of the Unit are reflected on a current basis.

The Company made a provision in 1978 for a write-down of the carrying value of an investment made pursuant to the terms of a certain coal supply contract. After reassessing its situation with respect to such contract, an additional provision for a write-down was made in 1979. Charges were recorded of approximately $10,068,000 in 1978 and $13,564,000 in 1979 (after giving effect to income taxes of $9,297,000 and $12,264,000 in the respective years). Included in such charges are adjustments to reflect the difference between the cost and market value of coal purchased under such contract.

11. Commitments and Contingencies

The Company is engaged in a long-range construction program for which substantial commitments have been made (see Item 1.—"Construction Program—Estimated Costs" and "Business—Regulation").

The Company's public liability for claims resulting from any nuclear incident is limited to $560 million under provisions of the Price-Anderson Act which also provides for nuclear liability insurance up to that amount. A portion of this insurance is provided through Nuclear Regulatory Commission regulations pursuant to which the Company could be assessed up to $5 million for each of its licensed reactors in connection with a nuclear incident involving any licensed facility in the nation and up to $10 million a year for each of its licensed reactors in the event of more than one incident. The Company had three licensed reactors at December 31, 1979.

Property damage coverage for certain of the Company's nuclear facilities is provided through membership in Nuclear Mutual Limited (NML). If NML's losses were to exceed its reserves, the Company would be liable, on a pro rata basis, for additional assessments of up to approximately $35 million, representing 14 times the Company's current annual premium to NML.

12. Supplementary Earnings Statement Information

In addition to the amounts of maintenance (including repairs) and provisions for depreciation of electric plant which are shown separately in the Statement of Earnings, other amounts, which are not significant, are charged to "Other Income—Other, net (deduction)" and to clearing and other accounts.

Research and development costs and advertising costs were each less than 1% of total revenues for each of the years reported. No royalties were paid.

The following tabulation sets forth, for the years indicated, provisions for general taxes:

	Year Ended December 31				
	1975	1976	1977	1978	1979
	(Dollars in Thousands)				
Real and personal property	$28,416	$30,345	$ 32,064	$ 34,917	$ 36,149
State and city franchise	40,682	48,375	54,884	61,140	67,308
Other	13,721	15,451	18,561	22,939	27,957
Total	$82,819	$94,171	$106,109	$118,996	$131,414
Charged to					
Electric expenses	$75,757	$85,215	$ 95,309	$103,816	$112,655
Construction	6,424	8,258	10,061	14,410	17,989
Other income	638	698	739	770	770
Total	$82,819	$94,171	$106,109	$118,996	$131,414

13. Constant Dollar Accounting (Unaudited)

During recent years the United States has experienced rapid inflation as contrasted with the relatively low level of inflation existing in the past. Continued inflation over time distorts traditional accounting measurements of income and capital. In an effort to produce financial information that discloses the effects of inflation, the Financial Accounting Standards Board issued Statement No. 33 requiring companies to explain the effects of inflationary factors on their operations. The following supplementary information should be viewed as an estimate of the effects of inflation on historical book capital investment. The Company's operation and maintenance expenses already include the average effects of inflation during the period in historical dollars and, therefore, no adjustments have been made to them. Since only historical costs are deductible for income tax purposes, no adjustments to income tax expense have been made in computing the impact of inflation.

Constant dollar amounts for electric plant in service (including land and land rights-of-way) were determined by indexing surviving historical costs of plant with the Consumer Price Index for all Urban Consumers (CPI-U) in order to trend the provision for depreciation to reflect the impact of general inflation.

Under the Company's ratemaking procedures, only the historical cost of plant in service is recoverable in rates as depreciation. Therefore, the excess of the constant dollar cost of plant (including CWIP) over the historical cost of plant is not presently recoverable in rates and is reflected in "Reduction in electric plant, including CWIP, stated in constant dollar amounts to recoverable amounts (historical cost)" in the table below.

The following table summarizes the estimated impact of inflation during 1979 on historical book investment based on the CPI-U (dollars in thousands):

	1979	
Earnings for common stock—in historical dollars	$222,198	
Adjustment to provision for depreciation to reflect general inflation	(112,172)	
Earnings for common stock adjusted for general inflation		$110,026
Other general inflation adjustments		
Reduction in electric plant, including CWIP, stated in constant dollar amounts to recoverable amounts (historical cost)	$(458,246)	
Adjustment to reduction for purchasing power loss covered by debt financing	387,032	
Other general inflation adjustments, net		$(71,214)

Five-year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices

(In Thousands of Average 1979 Dollars Except Per Share Figures)

	1975	1976	1977	1978	1979
Electric revenues					
—in historical dollars	$ 930,384	$1,108,358	$1,266,974	$1,396,720	$1,492,557
—in constant dollars	1,254,749	1,413,238	1,517,577	1,553,976	1,492,557
Earnings per share of common stock					
—in historical dollars	—	—	—	—	2.88
—in constant dollars	—	—	—	—	1.43
Common stock dividends per share					
—in historical dollars	1.40	1.525	1.63	1.74	1.83
—in constant dollars	1.89	1.94	1.95	1.94	1.83
Net assets at year-end					
—in historical dollars	—	—	—	—	1,758,016
—in constant dollars	—	—	—	—	1,662,430
Market price per common share at year-end					
—in historical dollars	19.50	22.00	22.00	19.375	17.25
—in constant dollars	25.49	27.44	25.70	20.76	16.31
Average Consumer Price Index for all Urban Consumers	161.2	170.5	181.5	195.4	217.4

14. Replacement Cost (Unaudited)

The estimated replacement cost of the Company's electric system (productive capacity) is presented below in compliance with the disclosure requirements of the Securities and Exchange Commission. This information does not purport to represent the current value of the existing electric plant in service; it is only an estimate of the cost that would be incurred if such assets were replaced at December 31, 1978 and December 31, 1979.

	1978		1979	
	Estimated Replacement Cost	Historical Cost	Estimated Replacement Cost	Historical Cost
	(Dollars in Thousands)			
Electric plant in service	$8,787,233	$3,964,825	$9,599,791	$4,126,513
Less accumulated depreciation and amortization	2,754,663	1,239,250	3,247,763	1,399,032
Electric plant in service, net	$6,032,570	$2,725,575	$6,352,028	$2,727,481

The amount of depreciation charged to expense was $119 million for 1978 and $130 million for 1979. The annual depreciation computed on the basis of estimated replacement cost would be $267 million for 1978 and $288 million for 1979.

Land and land rights and nuclear fuel are included in the replacement cost data above at their historical cost of $304 million for 1978 and $334 million for 1979. The replacement cost of thermo-generation facilities was determined by applying the Company's estimates of current construction costs (which reflect current environmental and regulatory requirements) for each type of thermo-generation to the actual capacity at year-end. The replacement cost of the remaining plant in service, including hydro-generation facilities, was determined by applying trending indices prepared specifically for the Company to the surviving plant by vintage.

The related accumulated depreciation based on replacement cost was developed by applying the ratio between gross plant and accumulated depreciation for each functional group (production, transmission, distribution and general facilities) on a historical cost basis to the estimated replacement cost of such group. Annual replacement cost depreciation was computed by applying the current book accrual rates for each functional group to its average replacement cost for the year.

Replacement cost has not been estimated for nuclear fuel because amortization of the cost is included in fuel expense and recognized through fuel cost adjustment procedures.

The difference between historical and estimated replacement cost of the net electric plant in service does not represent an unrecorded increment in the common shareholders' equity; rather it represents a theoretical additional capital investment which would be required if the electric plant in service were replaced in its entirety at December 31, 1978 and December 31, 1979. It is anticipated that, as the replacement cost of facilities is incurred in the future, electric rates will reflect, under present regulatory procedures, the higher depreciation expense associated with such investments.

DUKE POWER COMPANY

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT

For the Years Ended December 31, 1978 and December 31, 1979

(Dollars in Thousands)

Description	Balance Beginning of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1978					
Electric Plant in Service—At Original Cost					
Production	$1,819,836	$ 10,556	$ 842	$ 17	$1,829,567
Transmission	698,864	39,269	3,007	(546)	734,580
Distribution	1,032,793	67,737	8,163	4,397	1,096,764
General	100,344	34,337	976	12,191	145,896
Miscellaneous	10,211	(10)	—	—	10,201
Nuclear fuel	99,305	48,512	—	—	147,817
Total electric plant in service	3,761,353	200,401	12,988	16,059*	3,964,825
Construction Work in Progress	1,538,521	531,340	—	(225,538)**	1,844,323
Other Property—At Cost					
Water plant	16,691	798	1	(15)	17,473
Transit plant	525	—	—	—	525
Non-utility plant	8,705	(221)	20	(4)	8,460
Total other property	25,921	577	21	(19)*	26,458
Total plant	$5,325,795	$732,318	$13,009	$(209,498)	$5,835,606
For the Year Ended December 31, 1979					
Electric Plant in Service—At Original Cost					
Production	$1,829,567	$ 12,441	$15,632	$ (17)	$1,826,359
Transmission	734,580	37,932	1,169	301	771,644
Distribution	1,096,764	89,575	11,043	3,698	1,178,994
General	145,896	27,724	4,954	853	169,519
Miscellaneous	10,201	244	—	—	10,445
Nuclear fuel	147,817	21,735	—	—	169,552
Total electric plant in service	3,964,825	189,651	32,798	4,835	4,126,513
Construction Work in Progress	1,844,323	637,913	—	(279)	2,481,957
Other Property—At Cost					
Water plant	17,473	716	—	(2)	18,187
Transit plant	525	—	—	—	525
Non-utility plant	8,460	28	54	337	8,771
Total other property	26,458	744	54	335	27,483
Total plant	$5,835,606	$828,308	$32,852	$ 4,891*	$6,635,953

* Principally due to salvage credit, retirement cost, and adjustments for prior years.

** Represents the book value of an asset (the Catawba Nuclear Station) sold in November 1978.

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DUKE POWER COMPANY

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

For the Years Ended December 31, 1978 and December 31, 1979

(Dollars in Thousands)

Description	Beginning of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1978						
Accumulated Depreciation of Electric Plant						
Production	$ 505,077	$ 58,876	$ —	$ 826	$ —	$ 563,127
Transmission	174,249	20,218	—	3,303	(249)	190,915
Distribution	314,792	36,100	—	4,605	838	347,125
General	31,138	3,726	2,370	682	11,883	48,435
Miscellaneous	1,115	—	491	—	—	1,606
	1,026,371	118,920	2,861	9,416	12,472	1,151,208
Accumulated Amortization of Nuclear Fuel	41,732	—	46,310	—	—	88,042
	1,068,103	118,920	49,171	9,416	12,472	1,239,250
Accumulated Depreciation of Water Plant	4,361	325	—	1	—	4,685
Accumulated Depreciation of Transit Plant	112	38	—	—	—	150
Total Accumulated Depreciation	$1,072,576	$119,283	$49,171	$ 9,417	$12,472	$1,244,085
For the Year Ended December 31, 1979						
Accumulated Depreciation of Electric Plant						
Production	$ 563,127	$ 59,466	$ —	$15,648	$ —	$ 606,945
Transmission	190,915	21,314	—	788	(80)	211,361
Distribution	347,125	38,354	—	7,667	322	378,134
General	48,435	4,297	6,431	4,256	155	55,062
Miscellaneous	1,606	—	496	—	—	2,102
	1,151,208	123,431	6,927	28,359	397	1,253,604
Accumulated Amortization of Limited Term Plant			19			19
Accumulated Amortization of Nuclear Fuel	88,042	—	57,367	—	—	145,409
	1,239,250	123,431	64,313	28,359	397	1,399,032
Accumulated Depreciation of Water Plant	4,685	341	—	—	1	5,027
Accumulated Depreciation of Transit Plant	150	39	—	—	—	189
Total Accumulated Depreciation	$1,244,085	$123,811	$64,313	$28,359	$ 398	$1,404,248

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DUKE POWER COMPANY

SCHEDULE XII—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

For the Years Ended December 31, 1978 and December 31, 1979

(Dollars in Thousands)

Description	Balance Beginning of Year	Charged To Costs and Expenses	Deductions	Balance End of Year
For the Year Ended December 31, 1978				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$3,053	$3,903	$3,348(1)	$3,608
Other Reserves				
Operating Reserves(3)	$4,876	$3,896	$1,168(2)	$7,604
For the Year Ended December 31, 1979				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$3,608	$3,554	$3,031(1)	$4,131
Other Reserves				
Operating Reserves(3)	$7,604	$3,813	$1,886(2)	$9,531

(1) Uncollectible accounts written off, net of recoveries.

(2) Entries represent payments primarily for injuries and damages in North Carolina and South Carolina.

(3) Consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits," on the Balance Sheet.

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EXHIBIT I

DUKE POWER COMPANY

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE

(Dollars in Thousands)

This calculation is submitted in accordance with Release No. 9083 under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	Year Ended December 31				
	1975	1976	1977	1978	1979
Fully Diluted:					
Earnings applicable to common stock (A)	$82,799	$138,711	$153,470	$183,969	$222,198
Add: Dividends on Preference Stock, 6¼% Convertible Series AA	3,375	3,375	3,375	3,184	2,564
Earnings as adjusted for computation	$86,174	$142,086	$156,845	$187,153	$224,762
Average common shares outstanding—Twelve months (000)	51,020	57,767	63,630	70,367	77,168
Add: Common shares required for conversion of Preference Stock, 6¼% Convertible Series AA, $100 par, 500,000 shares authorized (336,062 shares outstanding as of December 31, 1979) (B)	1,898	1,956	1,956	1,716	1,359
Common shares as adjusted for computation	52,918	59,723	65,586	72,083	78,527
Fully diluted earnings per share	$1.63	$2.38	$2.39	$2.60	$2.86

(A) These figures agree with the related amounts in the Statement of Earnings.

(B) The conversion price used to convert the Preference Stock, 6¼% Convertible Series AA, into shares of common stock is $26.35, $25.56, $25.56, $24.73 and $24.73 for 1975, 1976, 1977, 1978 and 1979, respectively.

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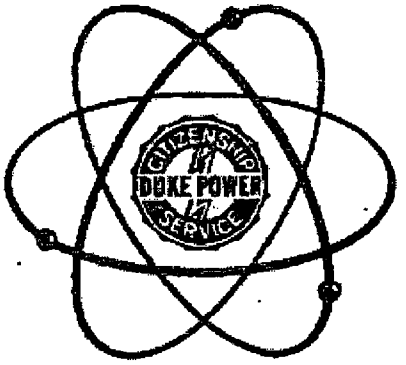

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SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1980 — Commission File Number: 1-4928

Duke Power Company

(Exact name of registrant as specified in its charter)

North Carolina (State or other jurisdiction of incorporation or organization)	56-0205520 (IRS Employer Identification No.)
422 South Church Street Charlotte, North Carolina (Address of principal executive offices)	28242 (Zip Code)

704-373-4317

(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
Preferred Stock, par value $100	
8.70% Series F	New York Stock Exchange
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
8.84% Series M	New York Stock Exchange
8.84% Series N	New York Stock Exchange
11% Series O	New York Stock Exchange
Preferred Stock A, par value $25	
10.76% Series 1975	New York Stock Exchange
Preference Stock, par value $100	
6¼% Convertible Series AA	New York Stock Exchange
First and Refunding Mortgage Bonds	
7⅛% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7⅛% Series B Due 2002	New York Stock Exchange
7¾% Series Due 2003	New York Stock Exchange
8⅛% Series B Due 2003	New York Stock Exchange
9¼% Series Due 2004	New York Stock Exchange
9½% Series Due 2005	New York Stock Exchange
8¾% Series Due 2006	New York Stock Exchange
8⅛% Series Due 2007	New York Stock Exchange
9⅛% Series Due 2008	New York Stock Exchange
10⅛% Series Due 2009	New York Stock Exchange
10⅛% Series B Due 2009	New York Stock Exchange
14⅛% Series Due 2010	New York Stock Exchange
14⅜% Series Due 1987	New York Stock Exchange
12% Series Due 1990	New York Stock Exchange
13⅛% Series B Due 2010	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, par value $100

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

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at February 13, 1981 ..... $1,177,261,239

Number of shares of Common Stock, without par value, outstanding at February 13, 1981 86,442,462

Documents incorporated by reference:

The registrant has incorporated herein by reference certain sections of its proxy statement relating to the 1981 annual meeting of shareholders to provide information required by the following parts of this annual report:

Part I—Item 4., Security Ownership of Certain Beneficial Owners and Management

Part III—Item 9., Directors and Executive Officers of the Registrant

—Item 10., Management Remuneration and Transactions

DUKE POWER COMPANY

FORM 10-K

ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION FOR THE YEAR ENDED DECEMBER 31, 1980

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PART I.

Item 1. *Business.*

DUKE POWER COMPANY

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,000,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1980, the Company's electric revenues amounted to approximately $1.7 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks ninth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242 (Telephone No. 704-373-4317).

Factors Affecting the Industry. The electric utility industry in general has been experiencing problems in a number of areas including the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities, particularly in the aftermath of the Three Mile Island accident; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; difficulty in obtaining sufficient capital on reasonable terms; difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

For a discussion of the developments affecting the Company, see "Construction Program" (pages 2 through 6), "Business—Rate Matters" (pages 8 and 9), "Business—Fuel Supply" (pages 9 through 12), "Business—Regulation—*Environmental Matters*" (pages 12 through 15) and "Business—Regulation —*Nuclear Facilities*" (page 15).

FINANCING PROGRAM

On February 6, 1981, the Company received $521 million from the sale of a 75% undivided interest in Unit No. 1 of the Catawba Nuclear Station to groups of its North Carolina and South Carolina rural electric cooperative customers. The proceeds of such sale are expected to substantially meet the Company's capital requirements for the remainder of 1981. During 1982 and 1983, the Company expects to obtain a major portion of its capital requirements through external sources with the types, amounts and timing of sales of securities to depend upon market conditions and other factors. The balance of such requirements is expected to be obtained from retained earnings, depreciation and amortization, deferred taxes, investment tax credit and other internal sources. The amount of internal cash will depend in part upon receiving future rate increases as to which no assurance can be given.

The sale of any further portion of the Catawba Nuclear Station would reduce the amount of external financing required by the Company by the amount initially received and by the amounts of progress payments to be made as additional construction costs are incurred. As described under "Construction Program—Facilities Under Construction", the Company has reached an agreement to sell a portion of its remaining interest in that Station to a group of its South Carolina municipal customers. Should such sale be consummated at the end of this year, the Company anticipates that it will receive approximately $235 million at that time. The Company has no assurance that such sale will be consummated.

In order to issue additional mortgage bonds and preferred stock, the Company must comply with earnings coverage and assets requirements contained in its mortgage indenture and articles of incorporation. Under the provisions of such indenture, additional bonds (other than certain types of refunding bonds) may not be issued unless the Company's available net earnings (as defined) for 12 consecutive calendar months within the 15 calendar months immediately preceding shall have been at least twice the amount of the annual interest charges on all bonds outstanding and applied for under the indenture. Additional bonds may be issued only against cash, certain retired bonds and in the amount of 66⅔% of the aggregate of the net amounts of additional property certified to the trustee pursuant to the indenture.

Under its articles of incorporation, the Company may not issue additional shares of preferred stock unless, after giving effect thereto, (i) its net earnings available for dividends on the preferred stock for any 12 consecutive calendar months within the 15 calendar months preceding the month in which the additional shares are to be issued shall have been at least twice the dividend requirements for a 12-month period upon the entire amount of preferred stock and all other stock ranking prior to or on a parity with the preferred stock, and (ii) the total net assets of the Company at a date not more than 90 days prior to the date on which the additional shares are to be issued shall equal at least twice the aggregate amount payable upon the involuntary liquidation of the Company to the holders of the preferred stock and all other stock ranking prior to or on a parity with the preferred stock.

On the basis of these requirements, the Company's interest and dividend coverages for the years shown were as follows:

	Year Ended December 31		
	1980	1979	1978
Mortgage bond interest	2.73	3.11	3.47
Preferred stock dividends	5.45	5.28	4.85

As of December 31, 1980, the Company could have issued under the earnings test contained in its mortgage indenture approximately $600 million principal amount of bonds, assuming an interest rate of 13% and utilization of the Company's construction work in progress, the major portion of which is nuclear, as property additions under the mortgage indenture. As of such date, the Company could have issued approximately $650 million of preferred stock based upon the amount of net assets of the Company available upon liquidation as provided in its articles of incorporation.

CONSTRUCTION PROGRAM

Estimated Costs

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rate increases), the availability and cost of capital in the financial markets, the availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise (see "Opposition to Nuclear Power Development") and changing regulatory and environmental standards (see "Business—Regulation—*Environmental Matters*"). The estimates of construction costs and the timing of construction expenditures are also subject to the sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to a group of its South Carolina municipal customers. The Company is keeping its construction program as flexible as possible in order to accommodate any variations as a result of such considerations.

Costs for the construction program, including the acquisition of nuclear fuel, for each of 1981, 1982 and 1983 and for the three-year period 1981-1983, as now scheduled, are currently estimated, assuming no

further sale of the Company's remaining interest in the Catawba Nuclear Station, as follows (in millions of dollars):

Type of Facilities	1981	1982	1983	1981-1983
Generation	$399	$325	$250	$974*
Transmission	45	52	56	153
Distribution	104	118	136	358
Other	22	35	35	92
Total	$570**	$530**	$477**	$1,577**
Nuclear Fuel	$128	$198	$140	$466*

* Cost estimates for the three-year period 1981-1983 do not include costs related to the Cherokee Nuclear Station (see "Facilities Under Construction"). Cost estimates for 1982 and 1983 include approximately $106 million attributable to the portion of the Catawba Nuclear Station which the Company has agreed to sell to a group of its South Carolina municipal customers.

** The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation utilizing Bureau of Labor Statistics indices.

The Company is continuing to experience increases in the cost of construction of new facilities as a result of recurring rises in the costs of materials, labor and capital, and increasing capital commitments attributable to more stringent regulatory requirements. However, the Company believes that in recent years it has been able to construct generating units at a lower cost per KW than generally experienced by other utilities for units of comparable type and vintage.

The Company currently is engaged in a comprehensive load management program designed to reduce the growth in peak demand without restricting the continued economic development of the Company's service area. Such program includes, among other things, promotion of energy-efficient building structures and appliances, use of residential conservation rates, use of interruptible rates for large customers, control by the Company (with customers' consent) of residential electric water heaters and air conditioners during peak demand periods and time-of-day pricing to a limited number of customers. The current and planned aspects of such program are designed to reduce the growth in peak demand by approximately 2,426,000 KW in the summer of 1989 and 3,513,000 KW in the summer of 1994 (from estimated peak demands at those times without load management) and to enhance generating reserve margins through the ability to interrupt approximately 687,000 KW of load in 1989 and 995,000 KW in 1994. The Company has premised its current construction program on estimated accumulated load management of approximately 546,000 KW for its summer peak load and approximately 769,000 KW for its winter peak load. (For information about the Company's peak loads, see "Business—Energy Requirements and Capability".)

The Company estimates a minimum reserve margin of approximately 14% above its anticipated peak load requirements through 1983. Based on the Company's current growth projections, its current and planned load management program, taking into consideration the availability of interruptible loads, and the recently revised construction program, it is anticipated that the minimum reserve margin would decrease to approximately 10% in 1990. The Company will continue to seek additional load management results and has the option of accelerating the scheduled completion of the Bad Creek Hydroelectric Station to improve the reserve margin at that time (see "Planned Facilities").

During the three-year period 1978-1980, gross property additions (including nuclear fuel) and net retirements amounted to approximately $2.4 billion and $180 million, respectively, resulting in a net increase of approximately $2.2 billion, or 42%, in gross plant. Net retirements include the interest in the Catawba Nuclear Station sold to the North Carolina Municipal Power Agency Number 1 (see "Facilities Under Construction").

Facilities Under Construction

The following table sets forth the major generating facilities of the Company currently under construction which are to be added to its present generating capability of 12,048,000 KW:

Unit and Location	Net KW Capability	Energy Source	Company Ownership (%)	Date of Planned Operation(1)	Estimated Construction Cost per KW(2)	Total Estimated Construction Costs(2)	Amounts Expended Through December 31, 1980(2)
						(Dollars in millions)	
McGuire No. 1	1,180,000	Nuclear	100	1981	$ 781	$1,842	$1,374
McGuire No. 2 (Northwest of Charlotte, in North Carolina)	1,180,000	Nuclear	100	1983			
Catawba No. 1	1,145,000	Nuclear	25	1984	1,196	685(3)	305(3)
Catawba No. 2 (Southwest of Charlotte, in South Carolina)	1,145,000	Nuclear	25	1985			
Cherokee No. 1	1,280,000	Nuclear	100	(4)	(4)	(4)	435
Cherokee No. 2 (Northeast of Spartanburg, in South Carolina)	1,280,000	Nuclear	100				

(1) Based on past experience, operational dates may vary due to construction delays, difficulties which may be encountered in obtaining regulatory approvals or in obtaining capital at reasonable costs, changes in load forecasts and other factors (see "Business—Regulation").

(2) These amounts exclude the costs of initial fuel cores.

(3) These amounts do not include the costs of the undivided interests sold to the North Carolina Municipal Power Agency Number 1 in 1978 and to groups of the Company's cooperative customers in February 1981 and assume no further sale of the Company's remaining interest in the Catawba Nuclear Station.

(4) Unit Nos. 1 and 2 of the Cherokee Nuclear Station, previously scheduled for completion in 1990 and 1992, have been delayed indefinitely due to difficulties in attracting the necessary capital on reasonable terms. Work on Unit No. 1 has been substantially reduced and work on Unit No. 2 has been interrupted while the Company fully evaluates its long-term options with respect to the Cherokee Nuclear Station. Accordingly, capital requirements for such nuclear station are undeterminable and are excluded from these cost estimates. Prior to such delay, construction costs for this nuclear station had been estimated at $118 million for 1981, $514 million for the three-year period 1981-1983, with a total cost for this facility of $6.7 billion. Although this delay may result in near-term reductions in costs that otherwise would be required, cost escalation and inflationary trends will, over the long term, increase construction costs per KW should this facility be rescheduled and constructed at a later date.

The Atomic Energy Commission, whose licensing and regulatory functions have been assumed by the Nuclear Regulatory Commission (NRC), issued construction permits in 1973 for both units of the McGuire Nuclear Station. An operating license is required before such units can be placed into commercial operation.

The Atomic Safety and Licensing Board of the NRC (ASLB) issued an initial decision in April 1979 with respect to the Company's applications for an operating license for the McGuire Nuclear Station. The ASLB stayed the effectiveness of such decision until its further order following the issuance of a supplement to the NRC staff's safety evaluation report addressing the significance of any unresolved generic safety issues. Subsequently, the Company requested the ASLB to terminate its stay. An intervenor, Carolina Environmental Study Group, then moved for the admission of new contentions and a reopening of the proceedings. The new contentions basically dealt with the consequences of a significant hydrogen release in a pressure suppression containment of Westinghouse design (such as the one in the McGuire Nuclear Station) including containment rupture and effects on health and safety of such releases. The Company subsequently filed for a low power license to load fuel, attain initial criticality and perform zero power physics testing which was issued on January 23, 1981. The ASLB began hearings on the hydrogen issue on February 24, 1981. The Company is unable to predict when it will receive authorization to begin the escalation of power levels.

In order to reduce its need for external financing, the Company, in 1978, sold to the North Carolina Municipal Power Agency Number 1 (NCMPA), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit No. 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. On February 6, 1981, the Company also sold to groups of its North Carolina and South Carolina cooperative customers a 75% undivided interest in Unit No. 1 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. Both sales were at cost plus a profit associated with the interests sold. The Company will continue to construct the facility and the purchasers will finance their respective portions of the construction costs by continued monthly progress payments.

The transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The Company will also maintain a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station commencing as early as 1982 under certain circumstances.

Agreement also has been reached between the Company and a group of its South Carolina municipal customers with respect to the purchase by a joint agency of such customers of the remaining 25% interest in Unit No. 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to the NCMPA. This agency, the Piedmont Municipal Power Agency (PMPA), was formed under legislation enacted by the South Carolina General Assembly. A lawsuit testing the constitutionality of such legislation is expected to be filed shortly. Any such sale would be subject to the upholding of the constitutionality of such legislation, and obtaining the necessary financing and regulatory approvals, as well as participation by a minimum number of members of the PMPA.

During 1980, the NCMPA's participating municipalities, which are presently wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and the proposed purchasers of the balance of Unit No. 2 accounted for approximately 3% of KWH sales and approximately 2% of revenues. The purchasers of a portion of Unit No. 1 of the Catawba Nuclear Station accounted for approximately 5% of KWH sales and approximately 4% of revenues. There is no assurance that such proposed sale to the PMPA will be consummated and, in the event that such sale is not consummated, the Company intends to complete and operate the facility as part of its system.

Planned Facilities

The Company has obtained a license from the Federal Power Commission, whose licensing and regulatory functions have been assumed by the Federal Energy Regulatory Commission (FERC), to construct the Bad Creek Hydroelectric Station, a pumped storage facility in Oconee County, South Carolina. Such facility, which is expected to have a generating capability of 1,000,000 KW, is scheduled for completion in the early 1990s but may be placed into service earlier if required. The total cost of such facility is expected to be approximately $794 million, of which $10.8 million was incurred through December 31, 1980.

The Company also has designed a third unit of the Cherokee Nuclear Station but has not scheduled its construction or exercised its options for the purchase of the major components.

In addition, the Company may construct an additional nuclear generating facility, southwest of Winston-Salem in North Carolina, to be known as the Perkins Nuclear Station. Such facility, which would be virtually identical to the Cherokee Nuclear Station, would consist of three generating units.

The Company has applied to the NRC for a construction permit for the Perkins Nuclear Station. Active opposition has been encountered at the environmental hearings for such permit and such opposition is continuing. The North Carolina Utilities Commission has issued a certificate of convenience and public necessity for such facility, which included certain restrictions requested by the North Carolina Environmental Management Commission on use of water from the Yadkin River.

General

The complexity of present-day electric utility technology and the time required for the construction of generating facilities and for the completion of the licensing and other regulatory proceedings relating thereto have compelled the Company, as well as other electric utilities, to make substantial investments in the construction of such facilities prior to the completion of licensing and regulatory proceedings. At December 31, 1980, the Company had incurred costs of approximately $2.6 billion for the McGuire, Catawba and Cherokee Nuclear Stations (including approximately $460 million with respect to the interest in the Catawba Nuclear Station sold on February 6, 1981 to groups of its cooperative customers), for which only construction permits had at that time been issued, and $10.8 million for the Perkins Nuclear Station, for which no such permit has yet been issued (see "Facilities Under Construction"). Under present NRC procedures, an operating license may be issued only when construction of a nuclear unit has been completed. Accordingly, the Company is necessarily making substantial investments in its facilities before regulatory proceedings are completed. There is no assurance that the necessary operating licenses and authorizations will be issued for such facilities.

Opposition to Nuclear Power Development

The development of nuclear power continues to be a subject of public controversy, particularly in the aftermath of the Three Mile Island accident (see "Business—Regulation—*Nuclear Facilities*"). Various groups have engaged in public protests, filed suits and participated in administrative proceedings and other activities, claiming that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. In addition, restrictive legislation relating to nuclear power has been proposed in Congress and in several state legislatures and referenda have been proposed to the electorate in certain states. Some of the claims made by such groups, if they should prevail, or the existence of the controversy itself, could delay or prevent the construction of nuclear generating units presently planned or under construction, or cause substantial modifications to or shutdowns of existing units.

The Company's studies continue to support its conclusion that the generation of electricity by nuclear power will be more economical than generation by fossil fuel, and the Company believes that its present construction program is compatible with the protection of the environment.

The Company understands that an issue was raised in litigation to which it was not a party relating to the allowance for funds used during construction (ADC) as reported by another public utility. It was alleged in this litigation that actual earnings were not properly presented in that ADC was included as "Other Income" without an adequate explanation of this item, and that ADC was not in fact income as generally understood, but rather a projection of future earnings not reflecting any actual yield on assets or any revenue during any fiscal period and not in fact earned upon completion of construction. ADC, which is not an item of current cash income, is included in the financial statements of the Company in accordance with the applicable system of accounts and in accordance with generally accepted accounting principles. The court granted summary judgment in favor of the defendants.

BUSINESS

Service Area

The Company supplies electric service directly to approximately 1,284,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to 37 other incorporated municipalities and to a number of rural electric cooperatives and private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco, furniture and chemical industries are of major significance to the economy of the area, and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, food products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $263 million of the Company's revenues for 1980, representing 16% of electric revenues and 49% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1980, its generation of electric energy for 1980 and certain corresponding information presently projected for 1981:

			Generating Capability(1)			Generation		
			Actual 1980		Projected 1981(2)	Actual 1980		Projected 1981(2)
Source	Facility		KW	%	%	KWH (millions)	%	%
Coal	Belews Creek		2,240,000			13,128		
	Marshall		1,900,000			11,791		
	Allen		1,100,000			5,604		
	Cliffside		770,000			4,040		
	Others		1,407,000			6,421		
		Total	7,417,000	61.6	56	40,984	71.6	67
Nuclear	Oconee		2,580,000	21.4	21	14,213	24.8	24
	McGuire(3)		—	—	7	—	—	6
		Total	2,580,000	21.4	28	14,213	24.8	30
Hydro	26 stations		1,452,000	12.0	11	1,820	3.2	3
Oil and Gas	Combustion turbines		599,000	5.0	5	203	0.4	—
		Total	12,048,000	100.0	100	57,220	100.0	100

(1) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(2) Projected figures are based on the assumption that required fuel is available and that there are no unforeseen contingencies.

(3) Unit No. 1 of the McGuire Nuclear Station, with a net capability of 1,180,000 KW, is scheduled for operation in 1981 (see "Construction Program").

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According to industry statistics through 1979, the Company ranked first in the nation for the last six consecutive years and for eight of the last ten years through 1979 in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Units at the Company's Belews Creek and Marshall Steam Stations were ranked as the first, second, third, fifth, sixth and seventh most efficient coal-fired steam generating units in 1979. Unit No. 3 of the Oconee Nuclear Station had the best heat rate in 1978 of all nuclear units in the nation according to statistics supplied by utilities to the NRC. Unit No. 1 ranked fourth in the nation as did the Oconee Nuclear Station itself. In prior years, operating reliability and availability of such nuclear units had been comparable to the average experience of the industry for units of similar size and vintage. The net capacity factors for the Oconee Nuclear Station were 70%, 63% and 63% for 1978, 1979 and 1980, respectively.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1980-1981 winter peak load to date of 10,530,000 KW occurred on January 12, 1981, and the 1980 summer peak load of 10,364,000 KW occurred on July 16, 1980. The 1979-1980 winter peak load of 9,892,000 KW occurred on February 5, 1980, and the 1979 summer peak load of 9,833,000 KW occurred on August 9, 1979.

Federal Energy Legislation

Congress adopted a national energy act in 1978 dealing with, among other things, utility rate design, including restrictions on the use of fuel adjustment clauses. Other sections of the legislation give FERC increased authority to order interconnections, power pooling and wheeling of power. The Company is presently unable to assess the impact of this legislation on its operations.

Rate Matters

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSC) must approve the Company's rates for retail sales within the respective States. FERC must approve the Company's rates for sales under its wholesale rate schedules.

General Rate Increases. The following table sets forth information concerning all rate increases requested or implemented by the Company since January 1, 1978. The revenues (in millions of dollars) shown are annualized on the basis of the filing test year.

Jurisdiction and Date Filed	Requested Revenues	Approved				
		Revenues	% of Request	% of Increase Over Previous Revenues	Rate Order Effective(1)	End of 12-Month Test Period
N. C. Retail:						
January 1978	$ 70.5	$40.3	57.2	5.3	September 1978	September 30, 1977
March 1979	35.5	28.3	79.7	3.2	October 1979	December 31, 1978
February 1980(2)	91.6	57.5	62.7	6.0	October 1980	December 31, 1979
S. C. Retail:						
April 1978	34.5	18.2	52.8	5.4	June 1979	December 31, 1977
August 1979(3)	25.8	23.4	90.5	6.0	September 1980	June 30, 1979
December 1980(4)	102.5	—	—	—	—	—
FERC Wholesale:						
June 1978	15.3	15.0	98.0	9.3	January 1980	December 31, 1978
June 1980(5)	26.3	18.6	70.7	8.9	February 1981	December 31, 1980

(1) The Company has generally collected interim rate increases, subject to refund, in all three jurisdictions. On occasion the Company has implemented its entire request on such a basis prior to the final rate order.

(2) The Company appealed this order to the North Carolina Court of Appeals in November 1980 on the grounds that expert testimony supporting a 15% return on common equity was not challenged or disputed during the hearings and that the amount of depreciation allowed was calculated contrary to the North Carolina statute.

(3) Intervenors appealed this order to the Court of Common Pleas, Richland County, in October 1980 on various grounds and are seeking its reversal or modification and refunds of amounts paid to the Company pursuant to its provisions.

(4) This increase was designed to cover higher operating costs, financing costs of certain facilities under construction and the costs associated with the operation of Unit No. 1 of the McGuire Nuclear Station.

(5) This increase was based on an agreement that allows the Company to maintain general parity between rates for its wholesale customers and rates for its North Carolina retail industrial customers. An interim increase of 6.71% was implemented in October 1980, and the remainder was implemented in February 1981.

The Company has not been able to earn the rates of return as allowed and defined by the NCUC and the PSC in recent rate proceedings since orders resulting therefrom were based on historical cost during inflationary periods. In the Company's most recent rate proceedings, the NCUC allowed a jurisdictional rate of return on common equity of 14.1%, and the PSC allowed a jurisdictional rate of return on common equity of between 12.5% and 13%.

The Company plans to file applications as soon as appropriate with the NCUC and FERC for additional rate increases designed to include in the rate base Unit No. 1 of the McGuire Nuclear Station upon its becoming operational. An extended delay in obtaining such increases would have a materially adverse impact on the Company's earnings.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The procedures for wholesale customers entail a 90-day lag from the date changes in fuel expense occur until they are reflected in bills to such customers. Beginning February 1, 1980, the procedures for North Carolina retail customers were modified to set the base fuel factor on a prior four months' experience and to limit changes in this factor to four-month intervals. The NCUC also will review the operation of the Company's base load generating facilities if its nuclear units generate at a capacity factor of less than 60%, in which event the Company has the specific burden of justifying the recovery of its incremental fuel costs. Effective June 1, 1979, the fuel cost recovery procedures for South Carolina retail customers were modified to set the base fuel factor semiannually after a public hearing to review fuel costs. The semiannual review will take into consideration fuel costs experienced during the preceding six months as well as fuel costs projected for the subsequent six months.

Fuel Supply

The Company presently relies principally on coal for the generation of electric energy, but it anticipates relying on nuclear power to a greater extent in the future (see "Construction Program"). The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source			Average Cost per Million BTU on a Burned Basis		
	Year Ended December 31			Year Ended December 31		
	1980	1979	1978	1980	1979	1978
Coal	71.6%	68.5%	65.4%	155.64¢	148.86¢	144.46¢
Nuclear	24.8	26.1	30.0	48.22	38.51	33.32
Oil and Gas	.4	.3	.9	300.16	246.16	262.76
All Fuels (cost based on weighted average)	96.8	94.9	96.3	127.00	116.81	109.09
Hydroelectric*	3.2	5.1	3.7			
	100.0%	100.0%	100.0%			

* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

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Coal. The Company obtains its coal under long-term supply contracts with mining operators utilizing both deep and surface mining, through its own mining operations, all of which are deep mine, and by open market purchases. During 1980, the Company obtained its coal requirements approximately as follows: 72% (11.1 million tons) under long-term contracts, 13% (2.0 million tons) from its own mining operations and 15% (2.3 million tons) by open market purchases.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1981 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. In order to further assure its coal supply, the Company has invested in independent coal mining operations located in eastern Kentucky.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. The Company purchased coal on a spot basis at an average delivered cost of $33.80 per ton, or 139.9¢ per million BTU, during 1980, as compared with an average delivered cost of $30.64 per ton, or 127.0¢ per million BTU, during 1979.

The following table sets forth the Company's estimated recoverable coal reserves from its own mining operations:

Estimated Recoverable Coal Reserves

As of December 31, 1980

(In Thousands of Tons)

State and Mine Location	Total	Average % Sulfur
Kentucky		
Eastover No. 1 (Highsplint)	65,800	0.9
Eastover No. 2 (Brookside)	30,000	0.9
Eastover No. 4 (Arjay)	48,900	1.2
Kentucky Border	19,000	1.0
	163,700	
Virginia		
Eastover No. 6 (Virginia City)	25,000	1.0
	188,700	

Such reserves represent the amounts of coal that can be expected to be recovered by underground mining from total coal reserves "in place" after allowing for unavoidable coal losses during mining and cleaning operations and for coal necessarily left in place for safety and other purposes. An overall recovery factor of 74.4% was used. The reserves lie within 2,500 feet from a known seam measurement, exclude rock partings within the seams and exclude seams of less than 30-inch thickness with minor exceptions, or where otherwise judged impractical to mine. The sulfur content of seams currently being mined at Eastover No. 4 (Arjay) is about 1.6% which is blended with a lower sulfur coal and used as a fuel. New seams planned for mining at that location beginning this year are expected to average 1.1% sulfur.

Additional coal tonnage of similar quality has been established at the Company's mining operations, but a determination of the degree to which this coal could be commercially mineable would require further evaluation which the Company does not intend to undertake at this time.

Federal legislation relating to the regulation of surface mining of coal was enacted in 1977. Such legislation, among other things, establishes standards restricting the surface mining of coal, requires the restoration of lands affected by surface mining and imposes a tax based upon the tonnage of coal mined to

be used for [illegible]. This legislation is adversely affecting the price of coal to the Company. It is anticipated that at least approximately 50% of the Company's coal supply will be provided through [illegible]

As the Company is [illegible] on coal for the generation of electricity, it endeavors to maintain an average coal supply of approximately 60 days. On February 13, 1981, the Company had on hand a coal supply of approximately 54 days.

The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the emission limitation for sulfur dioxide of 2.3 pounds per million BTU of heat input for existing facilities (see "Regulation - *Environmental Matters*").

The Company estimates that through the year 2000 its existing coal-fired generating units (see table under "Energy Requirements and Capability") will burn a total of approximately 317 million tons of coal. The Company presently expects to obtain approximately 15% of this estimated requirement from its own mining operations and has long-term agreements which, upon renewal as needed, would substantially provide the balance.

The Economic Regulatory Administration of the Department of Energy is authorized, under prescribed conditions, to allocate coal to achieve, among other things, the distribution of available low sulfur fuels on a priority basis to areas designated by the United States Environmental Protection Agency (EPA).

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations (see "Energy Requirements and Capability" and "Construction Program") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1990	1987	2009	1989
McGuire	1990	1987	2009	1989
Catawba	1990	1987	2009	1989

The Company has contracted for sufficient uranium material for the initial cores of Unit Nos. 1 and 2 of the Cherokee Nuclear Station and for enrichment services through 2011. The Company also has options to provide such Units with fabrication services through the mid-1990s. Options are also under consideration which would provide the Company with conversion services for its entire system through 1990.

Approximately 75% of the Company's commitments for uranium materials included in the preceding table is expected to be obtained from Rio Algom, Ltd., a Canadian supplier. Before making deliveries to the Company, such supplier must secure permits and export licenses from various Canadian governmental agencies, including the Atomic Energy Control Board, the Department of Industry, Trade and Commerce and the Uranium Exports Review Panel.

The Company purchased uranium material during 1980 at an average price of approximately $22 per pound. However, such price is expected to be substantially greater in future years. The Company's material nuclear supply contracts generally contain *force majeure* provisions and provide for price escalation under certain conditions.

The Company is endeavoring to obtain other fuel commitments although it cannot predict whether it will be successful nor can it estimate the costs involved. As a part of its efforts to obtain additional sources of uranium at a reasonable cost, a wholly-owned subsidiary of the Company, Western Fuel, Inc., has

entered into a joint venture in central Wyoming with Ogle Petroleum Inc., which is acting as operator. Such venture has established the feasibility of a new method for extracting uranium ore and has completed construction of the first phase of a commercial processing plant. Western Fuel's share of the cost of the plant, to be completed in the latter part of 1982, is estimated to be approximately $6 million. The joint venture is currently expecting a source materials license from the NRC which is required for full-scale commercial operation.

The Company has expended approximately $9 million to date in connection with this venture which includes Western Fuel's share of the cost of the first phase of the commercial processing plant. The amount of uranium presently estimated to be available from the project for the Company's use as a percentage of its presently estimated requirements over the life of the project is approximately 5%.

Although the reprocessing of spent fuel could make available to the Company an additional 20% of its nuclear fuel needs through 1990, there are currently no commercial reprocessing facilities in operation in the United States. The utilization of such facilities is dependent upon certain regulatory and policy decisions to be made by the Federal government. The Department of Energy has announced plans pursuant to which the Federal government would accept unreprocessed spent fuel and assume title to the material and responsibility for its storage and disposal in return for which the Company would pay a one-time charge. If reprocessing of spent fuel becomes available in the future, the stored spent fuel could be retrieved or the Company could receive compensation for the net value of such fuel.

The Company has adequate facilities for storage in the spent fuel pools at its Oconee Nuclear Station through mid-1982. The Company is presently involved in increasing storage facilities there which would extend its capacity until 1986. The Company has applied for a license to store spent fuel from the Oconee Nuclear Station in the spent fuel pool at the McGuire Nuclear Station currently under construction. Intervenors opposed the granting of such license and a decision was issued by the ASLB on October 31, 1980 denying the Company's application. The Company appealed such decision to the Atomic Safety and Licensing Appeal Board in November 1980 on the grounds that the ruling was based on the broad generic issue of unlimited spent fuel shipments over an extended period of time, rather than on the Company's request to transport a finite number of shipments over a specified period of time. The Company is also enlarging the capacity of the spent fuel pools at the McGuire and Catawba Nuclear Stations to accommodate larger amounts of spent fuel. Such modifications will enable the Company to have adequate facilities for the storage of its spent fuel until approximately 1990.

See "*Depreciation and Amortization*" under note 1 of Notes to Financial Statements for additional information regarding nuclear fuel costs.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC and EPA and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities (see "Construction Program"). The coal mining operations of Eastover Mining Company, the Company's coal mining subsidiary, are subject to the Coal Mine Health and Safety Act of 1969.

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1981-1983 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $152 million, including $42 million in 1981 and $46 million in 1982. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

AIR QUALITY. In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing standards limiting such emissions which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans.

With respect to particulate emissions, the implementation plans require compliance with an opacity standard based on the visual density of the flue gas and a mass emissions standard stated in terms of pounds per million BTU of heat input.

Although the Company believes it has installed the best available control technology in its coal-fired generating stations, it has determined that it could not consistently and continuously meet the stringent mass emission standards of the North Carolina implementation plan even though each unit had successfully completed stack performance tests. The Company filed for a variance from the particulate emission limitations, which was granted by the North Carolina Environmental Management Commission in June 1979 and approved by EPA in August 1980 as a revision to the State's implementation plan. In granting the variance for a three-year period, such Commission found that the Company had installed the best available control technology at its coal-fired generating stations and that independent air monitoring and modeling studies indicated that the emission limitations could be modified without violating State and Federal ambient air quality standards. The Commission also required that extensive performance tests be completed to determine if a correlation exists between opacity and mass emission standards and to provide data for the setting of a permanent mass emission standard. Under the variance, the interim mass emission standard ranges from 0.20 to 0.25 pounds per million BTU of heat input.

A revision of the North Carolina regulation limiting opacity for coal-fired generating units is currently under review by EPA. On August 28, 1980, EPA published its intent to approve the revision by which a previously planned stepdown in the limit from 40% to 20% was eliminated.

Following public notice and hearing, the North Carolina Environmental Management Commission approved in March 1977 a revision to the North Carolina regulation limiting emissions of sulfur dioxide from fuel-burning sources and submitted the revision to EPA for review and approval as required by the 1970 Act. The revision to the North Carolina State Implementation Plan eliminated a stepdown in the emission limit from 2.3 lbs. to 1.6 lbs. per million BTU of heat input which had been previously planned for July 1, 1980. To date, EPA has not decided whether to approve or disapprove the revision; however, EPA has indicated that it will not enforce the 1.6 lb. limit until final agency action is completed on the pending revision. If EPA disapproves the revision, the Company could be compelled to incur large capital costs for pollution control equipment in order to avoid noncompliance penalties.

In 1974 EPA issued regulations, applicable to the construction or expansion of facilities commenced after June 1, 1975, establishing a mechanism for "prevention of significant air quality deterioration" in areas where air pollution levels of sulfur dioxide and particulate matter are below the national ambient air quality standards. Amendments to the 1970 Act, adopted in 1977, include, among other things, requirements substantially similar to such regulations. The amendments also require EPA to establish stringent restrictions on emissions in non-attainment areas, to update new source performance standards for specified pollutants and to require the use of the best available technology rather than clean fuels to control emissions. The amendments also authorize EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and new civil penalties of up to $25,000 per day for facilities found to be in violation of an applicable implementation plan. EPA has promulgated new performance standards under these amendments which will apply to all stations not presently under construction and will require the use of scrubbers to remove sulfur dioxides, as well as other techniques to remove nitrogen oxides and particulate matter emissions. These amendments and proposed standards will affect the lead time, size and siting of future fossil-fueled generating stations as well as the type, complexity and cost of pollution control equipment to be used.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1972 (the 1972 Act) provided for the imposition of effluent limitations to regulate discharges of pollutants, including heat, into the waters of the United States. The 1972 Act mandated that there be achieved by July 1, 1977, with respect to existing plants, effluent limitations requiring application of the "best practicable control technology currently available" as well as compliance with state water quality standards. The Company has complied with these requirements. Regulations proposed under the 1972 Act also prescribed that the location, design and construction of cooling water intake structures reflect the "best technology available for minimizing environmental impact".

The 1972 Act required permits to ensure compliance with its provisions. The Company has received such permits for all of its generating stations either from EPA or under the permit programs of the States of North Carolina and South Carolina which have been approved by EPA.

In 1974 EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines required certain limitations on chemical discharges and imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit *(Appalachian Power Company, et al, v. Train)*. In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement and certain chemical limitations. The Company is unable at this time to determine what effect these developments will have on its operations.

In 1977 Congress adopted the Clean Water Act of 1977 (the 1977 Act) which amended the 1972 Act. The 1977 Act provides for three categories for controlling pollution: (1) conventional pollutants will require treatment by the best conventional pollutant control technology by July 1, 1984; (2) toxic pollutants will require application of the best available technology economically achievable by July 1, 1984; and (3) non-conventional pollutants will require application of the best available technology economically achievable within three years after effluent limitations are established, but no later than July 1, 1987. The 1977 Act also authorizes EPA to publish regulations to control station site runoff, spillage, leaks, sludge or waste disposal, and drainage from raw material storage which is associated with or ancillary to the source. The Company will be unable to determine the effect, if any, such legislation will have on its operations until the required regulations are promulgated.

OTHER ENVIRONMENTAL REGULATIONS. North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. South Carolina has also adopted regulations implementing its Hazardous Waste Management Act. The Company is in compliance with such Act and the regulations promulgated thereunder.

Polychlorinated biphenyls (PCBs) are regulated by provisions of the Toxic Substances Control Act. Major portions of the regulations issued by EPA implementing such provisions were set aside by the U. S. Court of Appeals for the District of Columbia. The Court stayed its mandate until January 21, 1981 at which time a joint motion for further stay of issuance of the mandate was filed. Such motion, which is pending, requested a stay of 18 months to avoid serious disruption of major industries and to provide time to comply with the Court's instruction that EPA build a sufficiently reliable factual record before promulgating regulations concerning the totally enclosed uses of PCBs or dealing with the complex problem of PCBs in low concentrations. The Company has agreed to implement an interim measures program to reduce risks associated with use of PCB transformers and PCB-contaminated transformers during the period in which the mandate is stayed.

GENERAL. Environmental regulations are in the process of development. Accordingly, the Company cannot estimate the effect of existing and potential regulations upon any of its existing and proposed

facilities. However, developments in these and other areas of regulation have in the past required the Company to modify or replace equipment and may in the future delay construction and operation of new or existing facilities at costs which could be substantial.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations currently permit public intervention with respect to issuances of permits and licenses.

In March 1979, Unit No. 2 of the Three Mile Island Nuclear Station, located near Harrisburg, Pennsylvania, experienced severe operating difficulties resulting in the shutdown of the Unit and presently undetermined damage to the reactor core. The nuclear steam supply system of such Unit is of Babcock & Wilcox design and manufacture as are those of the three units of the Company's Oconee Nuclear Station (see "Energy Requirements and Capability"). The nuclear steam supply systems of the Company's other nuclear generating facilities under construction or in the planning stage are of a different design and manufacture.

The Three Mile Island accident is causing a reexamination of certain safety standards and procedures for nuclear facilities and has led to an overall reassessment of nuclear power by various governmental entities.

As a result of the Three Mile Island accident, the NRC has developed an extensive list of requirements for the operation of nuclear facilities. In January 1980, the NRC issued an order requiring the Company to implement certain of such requirements on its three Oconee units or to shut down the units. The Company has completed the implementation of such requirements. Other longer term requirements are to be complied with prior to July 1, 1982. These include physical modifications of the units, additional analyses, changes in operating procedures and changes in staffing and training. The Company expects to complete the modifications during the next scheduled outages for refueling for each unit, but Unit No. 3 may be shut down for a short period later this year to effect the necessary changes.

The Company cannot predict what other effects the Three Mile Island accident or new NRC rules may have upon it, upon its ability to finance, upon the construction, licensing, cost or future operations of its nuclear units, or upon the Price-Anderson Act and the nuclear liability system.

The Company has insured against public liability claims resulting from nuclear incidents by purchasing the maximum available private insurance of $160 million, and the remaining $400 million of the $560 million limit on liability under the Price-Anderson Act has been provided by an indemnity agreement with the NRC. Effective in 1977, the NRC's indemnity began to be phased out in favor of a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors, and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance and indemnity coverage do not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $375 million, or the insurable value of the facilities, whichever is less. In connection with the sale in 1978 of a portion of its interest in the Catawba Nuclear Station (see "Construction Program"), the Company placed through a pool of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of the maximum coverage available, presently $300 million.

The Company is a member of Nuclear Electric Insurance Limited, a Bermuda mutual insurance company, which provides insurance against the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. The Company's Oconee Nuclear Station is insured for up to $2 million a week per unit, after a 26-week deductible period, with declining amounts per unit where more than one unit is involved. Coverages continue at 100% for 52 weeks and at 50% for an additional 52 weeks. This is presently the maximum amount available.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

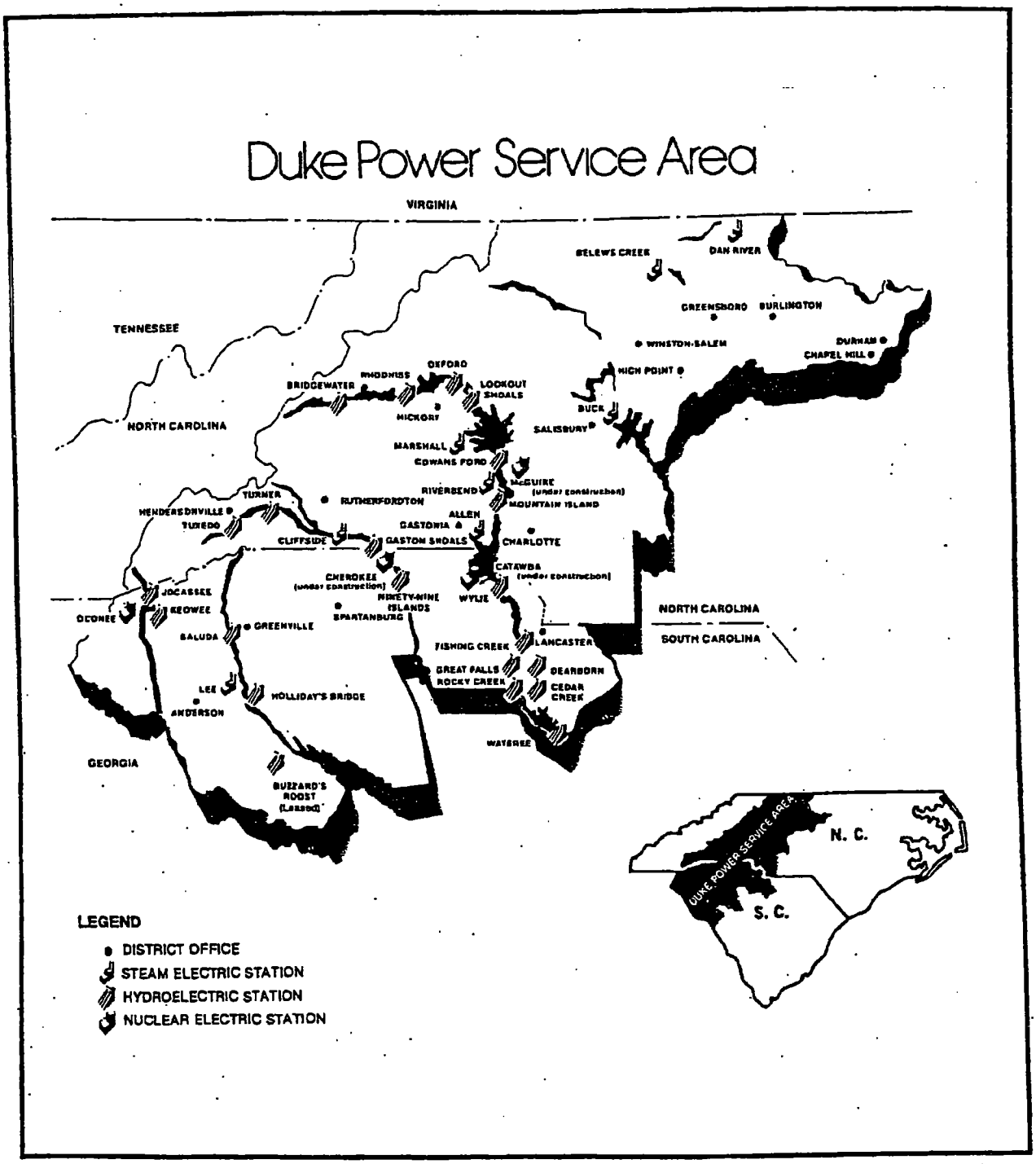
The Company has major interconnections and arrangements with its neighboring utilities which the Company considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

Employees

At December 31, 1980, the Company employed approximately 19,600 persons, of whom approximately 6,600 were engaged in generating plant construction including design and engineering. About 1,750 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW) with which the Company has a labor agreement which expires on September 30, 1981. The Company's coal mining subsidiary, Eastover Mining Company, employs approximately 1,100 persons, the majority of whom is represented by labor unions, including the United Mine Workers of America.


Duke Power Service Area
VIRGINIA
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
GEORGIA
BELEWS CREEK
DAN RIVER
GREENSBORO
BURLINGTON
WINSTON-SALEM
DURHAM
CHAPEL HILL
HIGH POINT
OXFORD
RHODHISS
BRIDGEWATER
LOOKOUT SHOALS
HICKORY
BUCK
SALISBURY
MARSHALL
COWANS FORD
McGUIRE (under construction)
RIVERBEND
MOUNTAIN ISLAND
TURNER
RUTHERFORDTON
HENDERSONVILLE
TUXEDO
ALLEN
GASTONIA
CLIFFSIDE
GASTON SHOALS
CHARLOTTE
CATAWBA (under construction)
CHEROKEE (under construction)
NINETY-NINE ISLANDS
SPARTANBURG
WYLIE
JOCASSEE
OCONEE
KEOWEE
GREENVILLE
SALUDA
FISHING CREEK
LANCASTER
GREAT FALLS
ROCKY CREEK
DEARBORN
CEDAR CREEK
LEE
ANDERSON
HOLLIDAY'S BRIDGE
WATEREE
BUZZARD'S ROOST (Leased)
DUKE POWER SERVICE AREA
N. C.
S. C.
LEGEND
DISTRICT OFFICE
STEAM ELECTRIC STATION
HYDROELECTRIC STATION
NUCLEAR ELECTRIC STATION

OPERATING STATISTICS

	Year Ended December 31				
	1980	1979	1978	1977	1976
Sources of Electric Energy—					
Millions of kilowatt-hours:					
Generated—net output:					
Coal	40,984	37,404	34,589	37,184	35,875
Nuclear	14,213	14,228	15,905	13,008	12,978
Hydro	1,820	2,809	1,941	1,852	1,961
Oil and gas	203	163	484	303	13
Total generated	57,220	54,604	52,919	52,347	50,827
Net interchange and purchased power	(472)	(512)	1,016	31	(1,656)
Losses and company use	(4,437)	(3,769)	(3,996)	(3,530)	(3,538)
Total energy sales	52,311	50,323	49,939	48,848	45,633
Average Cost Per Ton of Coal Burned	$37.85	$35.86	$34.24	$30.00	$26.21
Electric Energy Sales—					
Millions of kilowatt-hours:					
Residential	13,765	12,832	12,959	12,462	11,327
General service	9,395	8,778	8,920	8,623	7,987
Industrial	20,060	20,260	19,523	19,188	18,417
Wholesale and other energy sales	9,091	8,453	8,537	8,575	7,902
Total energy sales	52,311	50,323	49,939	48,848	45,633
Electric Revenues—					
Thousands of dollars:					
Residential	$ 565,633	$ 499,936	$ 469,389	$ 424,081	$ 372,348
General service	340,691	303,858	284,752	256,439	227,867
Industrial	534,790	508,605	448,550	402,003	361,310
Wholesale and other energy sales	232,506	201,938	188,428	173,832	149,094
Other electric revenues	9,202	(21,780)	5,601	10,619	(2,261)
Total electric revenues	$1,682,822	$1,492,557	$1,396,720	$1,266,974	$1,108,358
Number of Customers End of Period—					
Residential	1,105,035	1,078,419	1,049,543	1,024,712	989,501
General service	165,522	161,833	159,538	155,716	149,240
Industrial	7,588	7,475	7,231	6,947	6,752
Wholesale and other energy sales	6,260	5,950	5,857	5,688	5,472
Total customers	1,284,405	1,253,677	1,222,169	1,193,063	1,150,965
Residential Customer Statistics—					
Average number for period	1,095,933	1,068,194	1,039,275	1,016,482	982,548
Average annual use—KWH	12,560	12,013	12,469	12,260	11,528
Average annual billing	$516.12	$468.02	$451.65	$417.20	$378.96
Average Annual Billed Revenue Per KWH—					
Residential	4.11¢	3.90¢	3.62¢	3.40¢	3.29¢
General service	3.63¢	3.46¢	3.19¢	2.97¢	2.85¢
Industrial	2.67¢	2.51¢	2.30¢	2.10¢	1.96¢
Wholesale and other energy sales	2.56¢	2.39¢	2.21¢	2.03¢	1.89¢

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age*
Carl Horn, Jr.**	Chairman of the Board and Chief Executive Officer	1976	59
W. S. Lee**	President and Chief Operating Officer, and Director	1978	51
D. W. Booth**	Executive Vice President and Director	1976	56
W. H. Grigg**	Senior Vice President, Legal and Finance, and Director	1971	48
A. C. Thies**	Senior Vice President, Production and Transmission, and Director	1971	59
John D. Hicks**	Senior Vice President, Public Affairs, and Director	1971	57
W. H. Owen**	Senior Vice President, Engineering and Construction, and Director	1978	54
Thomas C. Berry	Vice President, Southern Division	1976	50
L. C. Dail	Vice President, Design Engineering	1978	55
Donald H. Denton, Jr.	Vice President, Marketing	1975	43
Robert L. Dick	Vice President, Construction	1971	53
George W. Ferguson, Jr.	Vice President, Governmental Affairs	1980	48
Steve C. Griffith, Jr.	Vice President and General Counsel	1977	47
M. T. Hatley, Jr.	Vice President, Rates	1979	58
Porter A. Hauser	Vice President and Controller	1980	63
E. N. Hedgepeth, Jr.	Vice President, Distribution Engineering, Construction and Operations	1978	53
Frank A. Jenkins	Vice President, Transmission	1971	61
S. T. Lattimore	Vice President, Computer Services	1979	54
John F. Lomax	Vice President, Western Division	1980	41
Joe S. Major, Jr.	Vice President, Personnel	1971	60
Joseph G. Mann	Vice President, Northern Division	1973	57
Paul H. Mann, Jr.	Vice President, Operation	1978	58
Dwight B. Moore	Vice President, Central Division	1980	59
Henry L. Cranford	Vice President, Division Operations	1980	53
William O. Parker, Jr.	Vice President, Steam Production	1974	56
Thomas M. Patrick, Jr.	Vice President, Eastern Division	1973	60
Richard R. Pierce	Assistant to the Chairman	1979	58
William R. Stimart	Vice President, Regulatory Affairs	1979	49
James W. White	Vice President, General Services	1979	55
Lewis F. Camp, Jr.	Secretary	1980	52
Richard C. Ranson	Treasurer	1976	39

* As of March 1981.

** Members of the Executive Committee.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Item 2. *Properties.*

The map on page 17 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V—Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company. Information concerning leases is set forth in note 7 of Notes to Financial Statements.

For additional information concerning the properties of the Company, see Item 1.—"Construction Program—Facilities Under Construction" and "Business—Fuel Supply".

Item 3. *Legal Proceedings.*

Reference is made to Item 1.—"Construction Program" for information relating to licensing proceedings before the Nuclear Regulatory Commission with respect to the Company's nuclear generating facilities under construction.

Reference is made to Item 1.—"Business—Rate Matters" regarding appeals taken from orders of the North Carolina Utilities Commission and The Public Service Commission of South Carolina and pending proceedings before The Public Service Commission of South Carolina and the Federal Energy Regulatory Commission.

Reference is made to Item 1.—"Business—Fuel Supply" regarding an appeal taken from a decision of the Atomic Safety and Licensing Board of the NRC denying the Company's application for a license to store spent fuel from the Oconee Nuclear Station in the spent fuel pool at the McGuire Nuclear Station.

Reference is made to Item 1.—"Business—Regulation—*Environmental Matters*" with respect to environmental proceedings involving the Company.

Item 4. *Security Ownership of Certain Beneficial Owners and Management.*

Information for this item is set forth in the sections entitled "Voting Securities Outstanding" and "Security Ownership of Management" in the proxy statement of the Company relating to its 1981 annual meeting of shareholders, which is incorporated herein by reference.

PART II.

Item 5. *Market for the Registrant's Common Stock and Related Security Holder Matters.*

The Common Stock of the Company is traded on the New York Stock Exchange. At February 13, 1981 there were approximately 129,000 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by *The Wall Street Journal* as composite transactions:

Common Stock	Dividends per Share	Price Range	
		High	Low
1980 by Quarter			
Fourth	$0.51	18¾	15⅛
Third	0.48	18⅛	16⅛
Second	0.48	19¼	16⅛
First	0.48	18¾	14⅛
1979 by Quarter			
Fourth	0.48	18⅛	16¼
Third	0.45	20⅛	18⅛
Second	0.45	19⅜	16⅛
First	0.45	20⅛	18¼

Reference is made to note 3 of Notes to Financial Statements for information concerning restrictions on the ability of the Company to pay dividends on shares of its Common Stock. At the date hereof, none of the Company's retained earnings was restricted with respect to the declaration or payment of dividends.

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Item 6. *Selected Financial Data.*

DUKE POWER COMPANY

SELECTED FINANCIAL DATA

	1980	1979	1978	1977	1976
	(Dollars in thousands, except per share figures)				
CONDENSED STATEMENTS OF INCOME					
Electric revenues	$1,682,822	$1,492,557	$1,396,720	$1,266,974	$1,108,358
Electric expenses	1,402,722	1,238,680	1,159,719	1,037,088	874,941
Electric operating income	280,100	253,877	237,001	229,886	233,417
Other income	208,365	168,612	131,899	96,955	89,535
Income before interest deductions	488,465	422,489	368,900	326,841	322,952
Interest deductions, net	177,374	147,729	138,299	134,492	149,251
Net income	311,091	274,760	230,601	192,349	173,701
Dividends on preferred and preference stocks	58,612	52,562	46,632	38,879	34,990
Earnings for common stock	$ 252,479	$ 222,198	$ 183,969	$ 153,470	$ 138,711
COMMON STOCK DATA					
Shares of common stock					
—Year end (thousands)	86,294	79,489	72,132	65,430	59,180
—Average (thousands)	81,985	77,168	70,367	63,630	57,767
Per share of common stock					
Earnings	$3.08	$2.88	$2.61	$2.41	$2.40
Dividends	$1.95	$1.83	$1.74	$1.63	$1.525
Book value—year end	$22.82	$22.12	$21.31	$20.53	$19.67
Market price—high-low	19¼-14⅛	20⅛-16¼	22-18⅛	23½-19⅛	23¾-16⅛
—year end	18⅛	17¼	19⅜	22	22
TOTAL ASSETS	$6,328,174	$5,615,372	$4,984,621	$4,610,706	$4,058,644
LONG-TERM DEBT	$2,594,008	$2,300,488	$1,974,209	$1,948,081	$1,892,505
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS	$ 316,559	$ 268,500	$ 220,000	$ 170,000	$ 120,000

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The Company seeks to provide reliable service to its customers at reasonable costs. This requires a continuing construction program which further requires the Company to be financially sound and to earn a competitive return to attract the necessary capital for its growth.

Liquidity and Capital Needs and Resources

During the period 1976 to 1980, gross property additions (including nuclear fuel) were $3.5 billion and retirements were $191 million, resulting in a net increase of $3.3 billion in gross plant. Projected construction and nuclear fuel costs for the period 1981 through 1983 total $1.6 billion and $466 million, respectively, excluding undeterminable requirements for the Cherokee Nuclear Station.

The construction program over any period of time requires expenditures greater than cash generated internally from operations. The Company initially funds the excess with short-term commercial paper and bank borrowings. While the Company has short-term credit capacity of $380 million, it prefers to limit short-term debt at any one time to $150 million. Since 1976 the Company has refunded all of its short-term debt at least once each year.

During the past five years, financings have included $1.1 billion in long-term debt (principally first and refunding mortgage bonds), $290 million in preferred stock and $600 million in common stock. Additionally, $260 million was obtained from the 1978 sale of a portion of the Catawba Nuclear Station. On February 6, 1981, the Company received $521 million upon completing the sale of an additional portion of the Catawba Nuclear Station to groups of its North Carolina and South Carolina rural electric cooperatives. In anticipation of that sale, short-term debt was permitted to reach $197 million at December 31, 1980.

Internal cash generation remains at only 25 to 30 percent of total capital requirements. The Company seeks to raise that percentage through achievement of a higher return on investment, and inclusion in rate base of additional construction work in progress and generating units nearing completion. Applications for rate increases are being filed seeking higher allowed returns and reflecting the commercial operation (expected in 1981) of McGuire Nuclear Station Unit 1. Also, sales of portions of the Catawba Nuclear Station will reduce future capital requirements and thereby improve the percentage of internal cash generation.

The Company continually reviews its capital requirements, conditions in the financial markets and its capitalization goals to determine the amounts, timing and types of external financings. At December 31, 1980, the Company's capitalization goals were 49 percent long-term debt, 13 percent preferred stock and 38 percent common equity.

To minimize future financings, the Company has designed a program to reduce construction needs as much as possible by comprehensive load management, which focuses on reducing the growth in peak demand without restricting the continued economic development of the Company's service area.

For additional discussion of the Company's financing program, see "Financing Program".

Results of Operations

Earnings per share have increased from $2.40 in 1976 to $3.08 in 1980. This improvement resulted primarily from revenues attributable to increases in base rates charged to customers, higher kilowatt-hour sales and increases in allowance for funds used during construction (ADC). The increases in base rates have come from general rate increases, fuel cost adjustment procedures and the inclusion of construction work in progress in rate base. Kilowatt-hour sales have increased from 45.6 billion in 1976 to 52.3 billion in 1980. The increase in ADC is attributable to a greater investment in construction work in progress and an increase in average ADC rates.

Inflation has had a significant impact on the Company's operations in recent years (see "Supplemental Financial Data—Effects of Changing Prices").

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Item 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company were prepared by management which is responsible for their integrity and objectivity. The statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions that should be included and the other information in the annual report is consistent with those statements. In preparing the financial statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. The Company's accounting controls provide reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected by employees within a timely period in the normal course of performing their assigned functions. The Company's accounting controls are continually reviewed for effectiveness and are augmented by written policies, standards and procedures, and a strong program of internal audit.

The board of directors pursues its oversight role for the financial statements through the audit committee, composed solely of directors who are not officers or employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each and to monitor the discharge by each of their responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte Haskins & Sells, who have free access to the audit committee or the board, without management present, to discuss internal accounting control, auditing and financial reporting matters.

AUDITORS' OPINION

DUKE POWER COMPANY:

We have examined the financial statements and supplemental schedules of Duke Power Company, listed in the accompanying index on page 23. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying balance sheets and statements of capitalization, income, retained earnings, and source of funds for plant construction costs present fairly the financial position of the Company at December 31, 1980 and 1979 and the results of its operations and the source of its funds for plant construction costs for each of the three years in the period ended December 31, 1980, in conformity with generally accepted accounting principles applied on a consistent basis. Also, in our opinion, the supplemental schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 24, 1981

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DUKE POWER COMPANY

STATEMENTS OF INCOME

	Year Ended December 31		
	1980	1979	1978
	(Dollars in thousands)		
ELECTRIC REVENUES (Notes 1 and 2)	$1,682,822	$1,492,557	$1,396,720
ELECTRIC EXPENSES			
Operation			
Fuel used in electric generation	680,693	589,402	543,319
Net interchange and purchased power (credit)	(12,908)	(17,254)	17,271
Wages, benefits and materials	211,014	180,338	155,443
Maintenance of plant facilities	114,597	94,598	78,605
Depreciation and amortization (Note 1)	131,441	125,437	120,839
General taxes	124,422	112,655	103,816
Income taxes (Notes 1 and 8)	153,463	153,504	140,426
Total electric expenses	1,402,722	1,238,680	1,159,719
Electric operating income	280,100	253,877	237,001
OTHER INCOME (Notes 1, 8 and 10)			
Allowance for equity funds used during construction	150,846	121,701	87,810
Earnings of subsidiaries, net	3,418	10,447	9,159
Other, net (deduction)	(3,299)	(20,314)	16,168
Income taxes—other, net	(982)	16,320	(16,963)
Income taxes—credit	58,382	40,458	35,725
Total other income	208,365	168,612	131,899
Income before interest deductions	488,465	422,489	368,900
INTEREST DEDUCTIONS			
Interest on long-term debt	220,271	179,363	165,926
Other interest	17,287	9,752	6,533
Allowance for borrowed funds used during construction (credit) (Note 1)	(60,184)	(41,386)	(34,160)
Total interest deductions	177,374	147,729	138,299
NET INCOME	311,091	274,760	230,601
Dividends on preferred and preference stocks	58,612	52,562	46,632
EARNINGS FOR COMMON STOCK	$ 252,479	$ 222,198	$ 183,969
COMMON STOCK DATA			
Average shares outstanding (thousands)	81,985	77,168	70,367
Earnings per share	$3.08	$2.88	$2.61
Dividends per share	$1.95	$1.83	$1.74

See notes to financial statements.

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DUKE POWER COMPANY

STATEMENTS OF SOURCE OF FUNDS FOR PLANT CONSTRUCTION COSTS

	Year Ended December 31		
	1980	1979	1978
	(Dollars in thousands)		
FUNDS FROM OPERATIONS			
Net income	$311,091	$274,760	$230,601
Non-fund items			
Depreciation and nuclear fuel amortization	210,600	190,110	170,373
Deferred income taxes and investment tax credit, net of amortization	68,198	91,991	89,786
Equity component of the allowance for funds used during construction	(150,846)	(121,701)	(87,810)
Other, net	2,989	(5,854)	(2,669)
Funds from operations	442,032	429,306	400,281
Dividends paid	(217,618)	(193,585)	(168,273)
Funds retained in the business	224,414	235,721	232,008
FUNDS FROM FINANCING AND SALE OF ASSETS—NET PROCEEDS			
First mortgage bonds	271,150	295,768	123,249
Common stock	105,829	131,561	124,667
Preferred stock	49,323	49,251	89,674
Nuclear fuel trusts	30,664	76,254	48,953
Term note	10,000	—	—
Sale of an interest in the Catawba Nuclear Station	—	—	260,047
Other financings	—	—	80
Increase (decrease) in notes payable for construction	85,000	112,000	(174,095)
Funds from financing and sale of assets	551,966	664,834	472,575
Total available funds	776,380	900,555	704,583
WORKING CAPITAL REQUIREMENT (INCREASE) DECREASE	(31,000)	(43,536)	11,330
RETIREMENTS OF LONG-TERM DEBT AND PREFERRED STOCK	(43,211)	(150,412)	(71,405)
PLANT CONSTRUCTION EXPENDITURES	702,169	706,607	644,508
Equity component of the allowance for funds used during construction	150,846	121,701	87,810
PLANT CONSTRUCTION COSTS	$853,015	$828,308	$732,318
SUMMARY OF PLANT CONSTRUCTION COSTS			
Production	$590,420	$571,023	$507,130
Transmission	51,300	42,566	27,326
Distribution	92,990	89,841	77,685
General	25,000	26,812	17,468
Subtotal	759,710	730,242	629,609
Nuclear fuel	93,305	98,066	102,709
PLANT CONSTRUCTION COSTS	$853,015	$828,308	$732,318

See notes to financial statements.

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DUKE POWER COMPANY

BALANCE SHEETS

ASSETS

	December 31	
	1980	1979
	(Dollars in thousands)	
ELECTRIC PLANT		
(At original cost—Notes 1, 6 and 7)		
Electric plant in service	$4,419,152	$4,126,513
Less accumulated depreciation and amortization	1,629,109	1,399,032
Electric plant in service, net	2,790,043	2,727,481
Construction work in progress	3,114,807	2,481,957
Total electric plant, net	5,904,850	5,209,438
OTHER PROPERTY AND INVESTMENTS		
Other property—at cost (less accumulated depreciation: 1980—$4,551; 1979—$5,216)	22,447	22,267
Investments in and advances to subsidiaries (Note 1)	34,373	18,412
Other investments—at cost or less	8,845	8,809
Total other property and investments	65,665	49,488
CURRENT ASSETS		
Cash (including time deposits of $1,282 in 1979) (Note 9)	1,835	4,833
Receivables (less allowance for losses: 1980—$4,064; 1979—$4,131)	128,549	142,751
Materials and supplies—at average cost		
Coal	133,156	130,889
Other	79,552	67,800
Prepayments	5,334	1,528
Total current assets	348,426	347,801
DEFERRED DEBITS		
Debt expense, being amortized over terms of related debt	3,282	2,932
Other	5,951	5,713
Total deferred debits	9,233	8,645
TOTAL ASSETS	$6,328,174	$5,615,372

See notes to financial statements.

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DUKE POWER COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31	
	1980	1979
	(Dollars in thousands)	
CAPITALIZATION		
(See Statements of Capitalization)		
Common stock equity	$1,969,140	$1,758,016
Preferred and preference stocks without sinking fund requirements	395,858	408,606
Preferred stocks with sinking fund requirements	316,559	268,500
Long-term debt	2,594,008	2,300,488
Total capitalization	5,275,565	4,735,610
CURRENT LIABILITIES		
Accounts payable	61,127	94,191
Interest accrued	71,056	55,501
Taxes accrued	45,610	41,286
Other	24,282	11,301
Total	202,075	202,279
Notes payable for construction—pending permanent financing (Note 9)	197,000	112,000
Current maturities of long-term debt and preferred stock	74,110	41,267
Total current liabilities	473,185	355,546
ACCUMULATED DEFERRED INCOME TAXES (Notes 1 and 8)	374,684	341,650
DEFERRED CREDITS		
Investment tax credit (Notes 1 and 8)	193,276	162,945
Other	11,464	19,621
Total deferred credits	204,740	182,566
COMMITMENTS AND CONTINGENCIES (Notes 7 and 11)		
TOTAL CAPITALIZATION AND LIABILITIES	$6,328,174	$5,615,372

See notes to financial statements.

DUKE POWER COMPANY

STATEMENTS OF CAPITALIZATION AND RETAINED EARNINGS

CAPITALIZATION

	December 31	
	1980	1979
	(Dollars in thousands)	
COMMON STOCK EQUITY (Note 3)		
Common stock, no par, 100,000,000 shares authorized; 86,294,416 and 79,488,939 shares outstanding for 1980 and 1979, respectively	$1,535,895	$1,414,791
Retained earnings	433,245	343,225
Total common stock equity	1,969,140	1,758,016
PREFERRED AND PREFERENCE STOCKS WITHOUT SINKING FUND REQUIREMENTS (Note 4)		
Preferred stock	375,000	375,000
Preference stock	20,858	33,606
Total preferred and preference stocks without sinking fund requirements	395,858	408,606
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS (Note 5)		
Preferred stock	260,000	210,000
Preferred stock A	56,559	58,500
Total preferred stocks with sinking fund requirements	316,559	268,500
LONG-TERM DEBT (Note 6)		
First and refunding mortgage bonds	2,418,000	2,149,750
Sinking fund debentures, 4¼% - due 1982	25,000	25,000
Term note, 9.025% - due 1985	10,000	—
Pollution control obligations, 75% of prime rate - due 1983	2,500	2,500
Capitalized leases (Note 7)	103,862	51,591
Nuclear fuel trusts	125,000	125,000
Unamortized debt discount and premium, net	(16,244)	(13,586)
Current maturities of long-term debt	(74,110)	(39,767)
Total long-term debt	2,594,008	2,300,488
TOTAL CAPITALIZATION	$5,275,565	$4,735,610

RETAINED EARNINGS

	Year Ended December 31		
	1980	1979	1978
	(Dollars in thousands)		
BALANCE—Beginning of year	$343,225	$266,173	$207,897
ADD—Net income	311,091	274,760	230,601
Total	654,316	540,933	438,498
DEDUCT			
Dividends			
Common stock	159,240	141,035	121,961
Preferred and preference stocks	58,612	52,562	46,632
Capital stock expense	3,219	4,111	3,732
Total deductions	221,071	197,708	172,325
BALANCE—End of year	$433,245	$343,225	$266,173

See notes to financial statements.

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DUKE POWER COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

A. *Additions to Electric Plant.* The Company capitalizes all construction-related direct labor and materials, as well as indirect construction costs, including general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized; the cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

B. *Allowance for Funds Used During Construction (ADC).* ADC is an accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are transferred from the statement of income to construction work in progress in the balance sheet and, accordingly, are capitalized in the same manner as construction labor and material costs. This item is recognized as a cost of "Electric Plant" with offsetting credits to "Other Income" and "Interest Deductions" because, under established regulatory rate practices, a utility is permitted to include a fair return on, and the recovery of, these capital costs through their inclusion in rate base and in the provision for depreciation.

ADC, which includes semi-annual compounding, was calculated on average embedded rates (net of applicable income taxes) of 8.10 percent, 8.01 percent and 7.13 percent for 1980, 1979 and 1978, respectively.

North Carolina statutes require that capital expenditures for construction work in progress (CWIP), incurred after July 1, 1979 and requested in rate applications after such date, be included in rate base for ratemaking purposes. Under such statutes, utilities are permitted to continue capitalizing ADC with respect to CWIP not included in rate base but are not permitted to do so with respect to CWIP included in rate base. At December 31, 1980, $174,218,000 of CWIP was included in North Carolina rate base and therefore excluded for purposes of capitalizing ADC.

C. *Depreciation and Amortization.* Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted average depreciation rates were 3.33 percent for 1980 and 1979 and 3.28 percent for 1978. All coal-fired generating units are depreciated at the rate of 3.57 percent. Beginning October 1979, the depreciation rate on nuclear plant was revised from 3.57 percent to 4.00 percent. The Company is continuing to evaluate the impact of nuclear plant decommissioning costs. Provisions for amortization of nuclear fuel, which are included in "Fuel used in electric generation," are recorded using the unit of production method. Due to the present unavailability of reprocessing facilities, nuclear fuel amortization includes an estimate of disposal costs.

D. *Subsidiaries.* The Company has five wholly-owned operating subsidiaries. Mill-Power Supply Company is a wholesale jobber and distributor of electrical supplies and equipment and acts as purchasing agent for the Company. Crescent Land & Timber Corp. is a land management and forestry company, whose principal holdings are non-utility land acquired from the Company. Eastover Mining Company mines coal for the Company (supplying 13 percent of its requirements for 1980) on properties owned or leased by Eastover Land Company, the Company's mineral holding subsidiary. Western Fuel, Inc. is involved in the exploration and development of uranium ore deposits in central Wyoming.

The Company follows the equity method of accounting for such subsidiaries. Retained earnings include $26,742,000 of undistributed earnings of subsidiaries at December 31, 1980. Cash dividends received from subsidiaries were $1,675,000 in 1980, $5,800,000 in 1979 and $2,600,000 in 1978.

E. *Income Taxes.* The Company and its subsidiaries file a consolidated federal income tax return. Income taxes are allocated to each company based on its taxable income or loss.

The Company's income taxes are allocated to electric operating expense and to non-electric operations under "Other Income." The "Income taxes—credit" classified under "Other Income" results from tax deductions of interest costs relating to investments in non-utility properties, mainly CWIP not included in rate base.

The Company provides deferred income taxes for timing differences between book and tax income, principally resulting from accelerated tax depreciation, capitalized taxes and employee benefits, repair allowance and cost of removal, and nuclear fuel disposal costs.

Investment tax credit is being deferred and amortized over the depreciable lives of the related properties. At December 31, 1980, the Company had unused investment tax credit approximating $47 million, which will be available for use through 1987.

F. *Retirement Plan.* The Company and two of its subsidiaries have a non-contributory defined benefit retirement plan for employees. The Company's policy is to fund pension costs accrued which amounted to $26,782,000 in 1980, $23,844,000 in 1979 and $20,053,000 in 1978. The Company amended its retirement plan effective September 1, 1980, to provide for certain plan changes including increased benefits for active and retired employees. These changes did not significantly affect the Company's pension costs.

Using an assumed rate of return of 7.5 percent, the actuarial present value of vested and nonvested accumulated plan benefits totaled approximately $126,757,000 and $13,090,000, respectively, at December 31, 1979, the date of the latest actuarial report. The plan's net assets available for benefits were approximately $176,840,000 and $134,861,000 at December 31, 1979 and 1978, respectively.

G. *Fuel Cost Adjustment Procedures.* The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel costs. Procedures for North and South Carolina retail jurisdictions provide for periodic reviews of fuel costs with provisions for changing such costs in base rates. With respect to South Carolina, the Company continues to reflect in revenues the difference between actual fuel costs incurred and fuel costs recovered through base rates. Procedures for the wholesale jurisdiction provide for monthly fuel cost adjustments.

2. Rate Matters

General rate increases since January 1, 1978 are as follows (dollars in thousands):

Jurisdiction and Date Implemented	Percent Increase	Annualized on 1980 Sales	Approximate Revenue Recorded		
			1980	1979	1978
N. C. Retail					
September 1, 1978	5.27	$43,800	$ 43,800	$43,300	$12,700
October 8, 1979	3.20	30,900	30,900	6,800	—
October 3, 1980	6.03	59,900	14,800	—	—
S. C. Retail					
September 1, 1978	5.40	18,900	18,900	18,900	8,600
October 8, 1979	6.02	25,200	25,200	4,900	—
Wholesale					
September 1, 1978	5.61	9,700	9,700	9,100	2,500
October 8, 1979	3.45	6,500	6,500	1,400	—
October 3, 1980	6.71	13,200	3,300	—	—
		$208,100	$153,100	$84,400	$23,800

3. Common Stock and Retained Earnings

Common Stock

In 1980, 1979 and 1978 the Company received $108,361,000, $134,924,000 and $128,074,000 from the issuance of 6,278,820 shares, 6,999,292 shares and 6,398,149 shares of common stock, respectively.

At December 31, 1980, certain shares of common stock were reserved for issuance as follows:

	Shares
Stock Purchase-Savings Program for Employees	1,490,258
Conversion of Preference Stock	884,863
Dividend Reinvestment and Stock Purchase Plan	44,217
Employees' Stock Ownership Plan	16,611
Total	2,435,949

Retained Earnings

The indenture relating to the 4¼% Sinking Fund Debentures due September 1, 1982 contains, among other things, the most restrictive provision on the payment of cash dividends. Under the terms of such indenture, none of the Company's retained earnings as of December 31, 1980 was restricted with respect to the declaration or payment of dividends.

4. Preferred and Preference Stocks Without Sinking Fund Requirements

At December 31, 1980 and 1979, 10,000,000 shares of preferred stock ($100 par value) were authorized and issuable with or without sinking fund requirements. At December 31, 1980 and 1979, 3,750,000 shares were outstanding without sinking fund requirements. In addition, 1,500,000 shares of preference stock ($100 par value) were authorized at December 31, 1980 and 1979, of which 208,586 shares and 336,062 shares were outstanding, respectively.

Preferred and preference stocks without sinking fund requirements at December 31, 1980 and 1979 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1980	1979
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
8.70% F	1970	600,000	60,000	60,000
8.20% G	1971	600,000	60,000	60,000
7.80% H	1972	600,000	60,000	60,000
8.28% K	1977	500,000	50,000	50,000
8.84% M	1978	400,000	40,000	40,000
6¼%, AA Convertible	1969	208,586	20,858	—
		336,062	—	33,606
Total			$395,858	$408,606

The outstanding Preference Stock, 6¾% Convertible Series A.A, is convertible into shares of common stock at the adjusted conversion price of $23.89 per share, each share of preference stock being taken at $100 for such purpose. The conversion price is subject to certain adjustments designed to protect the conversion privilege against dilution. In 1980, 1979 and 1978, 127,476 shares, 88,405 shares and 75,383 shares were converted into 526,657 shares, 357,418 shares and 304,108 shares of common stock, respectively.

5. Preferred Stocks With Sinking Fund Requirements

At December 31, 1980 and 1979, 10,000,000 shares of preferred stock ($100 par value) were authorized and issuable with or without sinking fund requirements. At December 31, 1980 and 1979, 2,600,000 shares and 2,100,000 shares, respectively, were outstanding with sinking fund requirements. In addition, 10,000,000 shares of preferred stock A ($25 par value) were authorized at December 31, 1980 and 1979, of which 2,340,000 shares and 2,400,000 shares were outstanding, respectively.

Preferred stocks with sinking fund requirements at December 31, 1980 and 1979 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1980	1979
7.35% I	1973	600,000	$ 60,000	$ 60,000
8.20% J	1977	500,000	50,000	50,000
8.375% L	1978	500,000	50,000	50,000
8.84% N	1979	500,000	50,000	50,000
11.00% O	1980	500,000	50,000	—
10.76% A	1975	2,340,000	58,500	—
		2,400,000	—	60,000
Less 83,000 shares of preferred stock A reacquired for current and future sinking fund requirements—at cost			(1,941)	—
Current sinking fund requirement, preferred stock A			—	(1,500)
Total			$316,559	$268,500

The preferred stock A current sinking fund requirement at December 31, 1980 will be met by delivering 60,000 shares of the 83,000 shares reacquired during 1980.

The annual sinking fund requirements through 1985 are $1,500,000 in 1981, $3,500,000 in 1982, $5,500,000 in 1983, $9,525,000 in 1984 and $9,525,000 in 1985, with additional redemptions in like amounts permitted at the Company's option.

The call provisions for the outstanding preferred and preference stocks specify various redemption prices not exceeding 111 percent of par values plus accumulated dividends to the redemption date.

6. Long-Term Debt

First and refunding mortgage bonds outstanding at December 31, 1980 and 1979 were as follows (dollars in thousands):

Series	Year Due	1980	1979
3¼%	1981	$ 35,000	$ 35,000
3⅛%	1986	30,000	30,000
14⅛%	1987	50,000	—
12%	1990	75,000	—
4½%	1992	50,000	50,000
4¼%B	1992	50,000	50,000
11%	1994	98,000	104,750
4½%	1995	40,000	40,000
5⅛%	1997	75,000	75,000
6⅛%	1998	75,000	75,000
7%	1999	75,000	75,000
8%B	1999	75,000	75,000
8½%	2000	75,000	75,000
8⅛%B	2000	100,000	100,000
7½%	2001	100,000	100,000
Series (Continued)			
7⅛%B	2001	$ 40,000	$ 40,000
7¼%	2002	100,000	100,000
7⅛%B	2002	75,000	75,000
7¾%	2003	100,000	100,000
8⅛%B	2003	100,000	100,000
9¼%	2004	100,000	100,000
9½%	2005	100,000	100,000
8⅜%	2006	100,000	100,000
8⅛%	2007	125,000	125,000
9⅜%	2008	125,000	125,000
10⅛%	2009	150,000	150,000
10⅛%B	2009	150,000	150,000
14⅛%	2010	100,000	—
13⅛%B	2010	50,000	—
Total		$2,418,000	$2,149,750

Substantially all electric plant was mortgaged at December 31, 1980.

The annual maturities of long-term debt (including sinking fund requirements and capitalized lease principal payments) through 1985 are $74,110,000 in 1981, $74,809,000 in 1982, $49,224,000 in 1983, $36,899,000 in 1984 and $12,085,000 in 1985.

Included in the annual maturities are amounts relating to $125,000,000 in outstanding obligations under two nuclear fuel trusts. Such maturities are based on estimated nuclear fuel consumption. The Company intends to transfer title to additional nuclear fuel to the trusts to replace such amounts as fuel is consumed.

7. Leases

Rentals incurred under non-cancelable leases totaled $15,783,000, $15,044,000 and $23,801,000 for 1980, 1979 and 1978, respectively. Such rentals are charged primarily to operating expenses. Substantially all leases require the Company to pay taxes and operation and maintenance expenses, and contain options to purchase at the lessors' unrecovered cost or fair market value.

Future minimum lease payments under the Company's capital and operating leases are as follows (dollars in thousands):

	Capital Leases	Operating Leases	Total
1981	$ 12,060	$ 6,084	$ 18,144
1982	14,171	5,580	19,751
1983	11,745	5,199	16,944
1984	11,745	4,898	16,643
1985	11,745	3,792	15,537
Later years	146,352	14,844	161,196
Total minimum lease payments	207,818	$40,397	$248,215
Less amount representing interest	103,956		
Present value of net minimum lease payments	$103,862		

In prior years, certain of the Company's capital leases were accounted for as operating leases. These leases were capitalized as of December 31, 1980. The effect of such capitalization on the Company's assets, liabilities and net income for prior years would not have been material.

8. Income Tax Expense

Income tax expense consisted of the following (dollars in thousands):

	1980	1979	1978
Electric Expenses			
Current income taxes			
Federal	$ 69,134	$ 61,698	$ 42,187
State	16,121	14,580	11,279
	85,255	76,278	53,466
Deferred taxes, net			
Excess tax over book depreciation	25,114	27,594	33,770
Capitalized taxes, employee benefits, etc.	17,680	16,545	13,720
Repair allowance and cost of removal	5,872	7,369	6,153
Nuclear fuel disposal costs	(12,263)	(10,800)	(9,610)
	36,403	40,708	44,033
Investment tax credit			
Deferred	36,854	41,196	45,467
Amortization of deferments (credit)	(5,049)	(4,678)	(2,540)
	31,805	36,518	42,927
Total electric expenses	153,463	153,504	140,426
Other Income			
Income taxes—other, net	982	(16,320)	16,963
Income taxes—credit			
Federal	(51,268)	(35,528)	(31,532)
State	(7,114)	(4,930)	(4,193)
Total income taxes—credit	(58,382)	(40,458)	(35,725)
Total income tax expense	$ 96,063	$ 96,726	$121,664

Income taxes payable currently were $30,037,000 for 1980, $19,500,000 for 1979 and $34,704,000 for 1978.

Deferred state income taxes were $3,896,000 for 1980, $4,399,000 for 1979 and $4,521,000 for 1978.

Income taxes differ from amounts computed by applying the statutory tax rate to pretax income as follows (dollars in thousands):

	1980	1979	1978
Income taxes on pretax income at the statutory federal rates of 46% for 1980 and 1979 and 48% for 1978	$187,291	$170,884	$169,087
Increase (reduction) in tax resulting from:			
Allowance for all funds used during construction (ADC)	(97,074)	(75,020)	(58,546)
Amortization of electric investment tax credit deferrals	(5,049)	(4,688)	(2,540)
State income taxes, net of federal income tax benefits	9,044	7,483	7,801
Other items, net	1,851	(1,933)	5,862
Total income tax expense (see above)	$ 96,063	$ 96,726	$121,664

9. Short-Term Borrowings

The Company has lines of credit with 78 commercial banks and uses these lines, plus the sale of commercial paper, to finance its current cash requirements. The Company also has revolving credit agreements with four commercial banks which run to December 1981, against which no borrowings had been made through December 31, 1980.

At December 31, 1980, the revolving credit agreements were on a fee basis and the lines of credit were on either a fee basis or compensating balance basis, with average annual balance requirements of $2,080,000. Bank loans, normally for 90 days or less, are principally at the lending bank's commercial prime interest rate. Certain of the Company's bank line arrangements may require additional balances of 10 percent of the borrowings on an annual average.

A summary of short-term borrowings and credit arrangements is as follows (dollars in thousands):

	1980	1979	1978
Amount outstanding at year end			
Commercial paper—average rates of 18.51% and 13.75%, respectively	$123,000	$ 87,000	—
Bank loans—average rates of 16.47% and 15.25%, respectively	$ 74,000	$ 25,000	—
Maximum amount outstanding during the year	$197,000	$125,400	$175,295
Average amount outstanding during the year	$ 84,466	$ 33,894	$ 61,695
Weighted average interest rate for the year—computed on a daily basis	12.91%	11.93%	7.68%
Lines of credit at year end	$280,400	$280,000	$280,000
Revolving credit agreements at year end	$100,000	$100,000	—

10. Other Income

In November 1978, the Company sold a 75 percent interest in Unit 2 of the Catawba Nuclear Station (Catawba) and 37.5 percent of the station's support facilities to the North Carolina Municipal Power Agency Number 1 (Agency) representing certain North Carolina municipal customers. A net of tax profit of approximately $11,242,000 from the sale was included in "Other Income." Income taxes of $24,927,000 related to the transaction reflect a taxable gain in excess of book gain resulting principally from the

treatment of ADC. As the Company completes construction of the unit, net profits included in progress payments made by the Agency are reflected on a current basis. At December 31, 1980, "Construction work in progress" included $787,700,000, representing the Company's investment in its remaining interest in Catawba.

The Company made provisions in 1979 and 1978 to write down the carrying value of an investment made pursuant to the terms of a certain coal supply contract and terminated that contract as of March 31, 1980. Charges were recorded of approximately $3,065,000 in 1980, $13,564,000 in 1979 and $10,068,000 in 1978 (after giving effect to income taxes of $2,973,000, $12,264,000 and $9,297,000, respectively). Included in such charges were adjustments to reflect the difference between the cost and market value of coal purchased under such contract.

11. Commitments and Contingencies

The Company is engaged in a long-range construction program for which substantial commitments have been made. Costs for the years 1981 through 1983 currently are estimated at $1.6 billion for the construction program, excluding undeterminable requirements for the Cherokee Nuclear Station (see Note 13), and $466 million for nuclear fuel. The program is subject to periodic review and revision, and actual construction costs to be incurred may vary from such estimates because of various factors including changing levels of inflation, revised load estimates, the cost and availability of capital, and the outcome of licensing and environmental matters.

The Company's public liability for claims resulting from any nuclear incident is limited to $560 million under provisions of the Price-Anderson Act which also provides for nuclear liability insurance up to that amount. A portion of this insurance is provided through Nuclear Regulatory Commission regulations pursuant to which the Company could be assessed up to $5 million for each of its licensed reactors in the event there is a nuclear incident involving any licensed facility in the nation with a maximum of $10 million a year for each of its licensed reactors in the event of more than one incident. At December 31, 1980, the Company had three licensed reactors.

Property damage coverage for certain of the Company's nuclear facilities is provided through membership in Nuclear Mutual Limited (NML). If NML's losses were to exceed its reserves, the Company could be liable, on a pro rata basis, for additional assessments of up to $41 million, representing 14 times the Company's current annual premium to NML.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), which provides insurance for the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. If losses were to exceed the accumulated funds available to NEIL, the Company would be liable for a retrospective premium adjustment of up to five times the regular annual premium. The maximum potential liability currently is estimated to be $21 million.

12. Reclassifications

Certain amounts in the 1979 financial statements have been reclassified to conform with 1980 classifications.

13. Subsequent Events

On February 6, 1981, the Company sold a 75 percent interest in Unit 1 of the Catawba Nuclear Station and 37.5 percent of the station's support facilities to groups of its North Carolina and South Carolina rural electric cooperatives and received $521 million at closing. Net profit on the sale was not significant. The terms of the agreements provide for, among other things, monthly progress payments from the cooperatives to finance future construction of their share of the station.

On February 24, 1981, the board of directors indefinitely delayed completion of the Cherokee Nuclear Station, citing difficulties in attracting capital on reasonable terms.

SUPPLEMENTAL FINANCIAL DATA

Quarterly Financial Data

	Electric Revenues	Electric Operating Income	Net Income	Earnings Per Common Share
	(Dollars in thousands, except per share figures)			
1980 by Quarter*				
Fourth	$425,219	$76,760	$76,764	$0.72
Third	450,861	66,433	77,877	0.77
Second	367,987	57,658	68,987	0.67
First	438,755	79,249	87,463	0.92
1979 by Quarter*				
Fourth	386,056	67,310	69,530	0.71
Third	374,089	55,215	64,826	0.65
Second	329,485	54,344	59,590	0.58
First	402,927	77,008	80,814	0.94

* Quarterly earnings generally fluctuate with seasonal weather conditions, timing of rate increases (including fuel cost adjustment procedures) and maintenance of electric generating units, especially nuclear-fueled units.

Effects of Changing Prices

In recent years, the impact of general inflation and changes in specific prices has caused distortions in traditional accounting measurements of income and capital. In response to this problem, the Financial Accounting Standards Board (FASB) issued Statement No. 33 requiring disclosure of the effects of inflation on a company's operations and financial position.

Because the accompanying supplementary information involves various assumptions and approximations, it should be viewed as an estimate of the effects of inflation, rather than a precise measurement.

Constant Dollar Accounting

Constant dollar accounting reflects the overall decline in the purchasing power of the dollar by restating historical costs in terms of dollars of equal purchasing power.

Constant dollar amounts for electric plant in service were determined by indexing surviving historical costs of plant with the Consumer Price Index for all Urban Consumers (CPI-U). Historical depreciation rates were applied to the restated amounts of plant thereby trending the provision for depreciation to reflect the impact of general inflation.

Current Cost Accounting

Current cost accounting reflects changes in specific prices of the property used in the Company's operations from the date the property was acquired to the present. This method differs from constant dollar accounting to the extent that costs of specific utility property have increased more or less rapidly than the rate of general inflation. The current cost amounts of plant in service represent the estimated cost for replacing existing plant facilities and were determined by indexing surviving plant costs by internally generated indices or the Handy-Whitman Index of Public Utility Construction Costs. Since plant facilities are not expected to be replaced precisely in kind, "current cost" does not necessarily represent the replacement cost of existing productive capacity. Current cost depreciation is computed by applying the same rates used in the historical cost and constant dollar statements to the current cost plant amounts.

Effects of Rate Regulation

Under the Company's present ratemaking procedures, only the historical cost of plant in service is recoverable in rates as depreciation. Therefore, the excess of the cost of plant stated in terms of constant

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dollars or current costs over the historical cost of plant, resulting from inflation in the current year, is not presently recoverable in rates as depreciation, and is reflected as a reduction to net recoverable cost.

The reduction is offset by the Company's having significant amounts of long-term debt outstanding which will be paid back in dollars of less purchasing power. Thus, the gain from decline in purchasing power of net amounts owed in the accompanying schedules results from inflation's effect on obligations to pay cash at a future date.

Other

Income statement items other than depreciation have not been adjusted. The Company's operation and maintenance expenses already include the average effects of changing prices during the period and, therefore, no adjustments have been made to them.

No adjustments to income tax expense have been made in computing the impact of inflation since only historical costs are deductible for income tax purposes.

Supplementary Statement of Earnings for Common Stock Adjusted for Changing Prices

	Year Ended December 31, 1980		
	Historical $	Constant Dollar	Current Cost
		(Dollars in thousands)	
Electric revenues	$1,682,822	$1,682,822	$1,682,822
Operating expenses	878,799	878,799	878,799
Maintenance of plant facilities	114,597	114,597	114,597
Depreciation	131,441	274,186	291,025
Taxes	277,885	277,885	277,885
Total operating expenses	1,402,722	1,545,467	1,562,306
Operating income	280,100	137,355	120,516
Other income	208,365	208,365	208,365
Income before interest	488,465	345,720	328,881
Interest expense	177,374	177,374	177,374
Net income	311,091	168,346	151,507
Dividends on preferred and preference stocks	58,612	58,612	58,612
Earnings for common stock	$ 252,479	$ 109,734*	$ 92,895
Increase in specific prices (current cost) of utility plant held during the year‡			$1,046,324
Reduction to net recoverable cost		$ (464,465)	(476,238)
Effect of increase in general price level			(1,017,712)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			(447,626)
Gain from decline in purchasing power of net amounts owed		412,266	412,266
Net		$ (52,199)	$ (35,360)

* If the reduction to net recoverable cost of $464,465,000 were reflected, and no recognition were given to the $412,266,000 purchasing power gain, earnings for common stock on a constant dollar basis would have been a loss of $354,731,000.

‡ At December 31, 1980, current cost of electric plant, net of accumulated depreciation, was $9,563,899,000.

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

	1980	1979	1978	1977	1976
	(In thousands of average 1980 dollars, except per share figures)				
Electric revenues					
In historical dollars	$1,682,822	$1,492,557	$1,396,720	$1,266,974	$1,108,358
In constant dollars	1,682,822	1,694,402	1,764,127	1,722,805	1,604,356
Income from continuing operations					
In historical dollars	311,091	274,760			
In constant dollars	168,346	184,575			
In current cost	151,507	161,252			
Earnings per share for common stock					
In historical dollars	3.08	2.88			
In constant dollars	1.34	1.62			
In current cost	1.13	1.32			
Common stock dividends per share					
In historical dollars	1.95	1.83	1.74	1.63	1.525
In constant dollars	1.95	2.08	2.20	2.22	2.21
Net assets at year end					
In historical dollars	1,969,140	1,758,016			
In constant dollars	1,880,742	1,887,248			
In current cost	1,880,742	1,887,248			
Market price per common share at year end					
In historical dollars	18.125	17.24	19.375	22.00	22.00
In constant dollars	17.31	18.52	23.57	29.18	31.15
Purchasing power gain on net monetary items	412,266	439,372			
Decrease in the current cost of electric plant in service, net of inflation, after reduction to net recoverable cost	447,626	499,051			
Average Consumer Price Index	246.8	217.4	195.4	181.5	170.5

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DUKE POWER COMPANY

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Balance Beginning of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1980					
Electric Plant in Service—At Original Cost					
Production	$1,826,359	$ 14,438	$ 635	$ 62,212	$1,902,374
Transmission	771,644	24,531	1,496	309	794,988
Distribution	1,178,994	90,271	10,993	4,667	1,262,939
General	169,519	19,338	3,842	22,806	207,821
Miscellaneous	10,445	5,177	—	—	15,622
Nuclear fuel	169,552	65,856	—	—	235,408
Total electric plant in service	4,126,513	219,611	16,966	89,994	4,419,152
Construction Work in Progress	2,481,957	632,850	—	—	3,114,807
Other Property—At Cost					
Water plant	18,187	1,494	1,040	(41)	18,600
Transit plant	525	—	—	—	525
Non-utility plant	8,771	(940)	446	488	7,873
Total other property	27,483	554	1,486	447	26,998
Total plant	$6,635,953	$853,015	$18,452	$ 90,441(1)	$7,560,957
For the Year Ended December 31, 1979					
Electric Plant in Service—At Original Cost					
Production	$1,829,567	$ 12,441	$15,632	$ (17)	$1,826,359
Transmission	734,580	37,932	1,169	301	771,644
Distribution	1,096,764	89,575	11,043	3,698	1,178,994
General	145,896	27,724	4,954	853	169,519
Miscellaneous	10,201	244	—	—	10,445
Nuclear fuel	147,817	21,735	—	—	169,552
Total electric plant in service	3,964,825	189,651	32,798	4,835	4,126,513
Construction Work in Progress	1,844,323	637,913	—	(279)	2,481,957
Other Property—At Cost					
Water plant	17,473	716	—	(2)	18,187
Transit plant	525	—	—	—	525
Non-utility plant	8,460	28	54	337	8,771
Total other property	26,458	744	54	335	27,483
Total plant	$5,835,606	$828,308	$32,852	$ 4,891(2)	$6,635,953
For the Year Ended December 31, 1978					
Electric Plant in Service—At Original Cost					
Production	$1,819,836	$ 10,556	$ 842	$ 17	$1,829,567
Transmission	698,854	39,269	3,007	(546)	734,580
Distribution	1,032,793	67,737	8,163	4,397	1,096,764
General	100,344	34,337	976	12,191	145,896
Miscellaneous	10,211	(10)	—	—	10,201
Nuclear fuel	99,305	48,512	—	—	147,817
Total electric plant in service	3,761,353	200,401	12,988	16,059(2)	3,964,825
Construction Work in Progress	1,538,521	531,340	—	(225,538)(3)	1,844,323
Other Property—At Cost					
Water plant	16,691	798	1	(15)	17,473
Transit plant	525	—	—	—	525
Non-utility plant	8,705	(221)	20	(4)	8,460
Total other property	25,921	577	21	(19)(2)	26,458
Total plant	$5,325,795	$732,318	$13,009	$(209,498)	$5,835,606

(1) Principally due to capitalization of leases at December 31, 1980.

(2) Principally due to salvage credit, retirement cost, and adjustments for prior years.

(3) Represents the book value of an asset (the Catawba Nuclear Station) sold in November 1978.

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DUKE POWER COMPANY

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Beginning of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1980						
Accumulated Depreciation of Electric Plant						
Production	$ 606,945	$ 61,722	$ —	$ 982	$31,989	$ 699,674
Transmission	211,361	22,228	—	167	(326)	233,096
Distribution	378,134	41,181	—	7,329	326	412,312
General	55,062	4,268	7,179	2,063	391	64,837
Miscellaneous	2,102	—	519	—	—	2,621
	1,253,604	129,399	7,698	10,541	32,380	1,412,540
Accumulated Amortization of Limited Term Plant	19	—	56	—	—	75
Accumulated Amortization of Nuclear Fuel	145,409	—	71,085	—	—	216,494
	1,399,032	129,399	78,839	10,541	32,380	1,629,109
Accumulated Depreciation of Water Plant	5,027	339	—	1,040	—	4,326
Accumulated Depreciation of Transit Plant	189	36	—	—	—	225
Total Accumulated Depreciation.	$1,404,248	$129,774	$78,839	$11,581	$32,380(1)	$1,633,660
For the Year Ended December 31, 1979						
Accumulated Depreciation of Electric Plant						
Production	$ 563,127	$ 59,466	$ —	$15,648	$ —	$ 606,945
Transmission	190,915	21,314	—	788	(80)	211,361
Distribution	347,125	38,354	—	7,667	322	378,134
General	48,435	4,297	6,431	4,256	155	55,062
Miscellaneous	1,606	—	496	—	—	2,102
	1,151,208	123,431	6,927	28,359	397	1,253,608
Accumulated Amortization of Limited Term Plant	—	—	19	—	—	19
Accumulated Amortization of Nuclear Fuel	88,042	—	57,367	—	—	145,409
	1,239,250	123,431	64,313	28,359	397	1,399,032
Accumulated Depreciation of Water Plant	4,685	341	—	—	1	5,027
Accumulated Depreciation of Transit Plant	150	39	—	—	—	189
Total Accumulated Depreciation.	$1,244,085	$123,811	$64,313	$28,359	$ 398	$1,404,248
For the Year Ended December 31, 1978						
Accumulated Depreciation of Electric Plant						
Production	$ 505,077	$ 58,876	$ —	$ 826	$ —	$ 563,127
Transmission	174,249	20,218	—	3,303	(249)	190,915
Distribution	314,792	36,100	—	4,605	838	347,125
General	31,138	3,726	2,370	682	11,883	48,435
Miscellaneous	1,115	—	491	—	—	1,606
	1,026,371	118,920	2,861	9,416	12,472	1,151,208
Accumulated Amortization of Nuclear Fuel	41,732	—	46,310	—	—	88,042
	1,068,103	118,920	49,171	9,416	12,472	1,239,250
Accumulated Depreciation of Water Plant	4,361	325	—	1	—	4,685
Accumulated Depreciation of Transit Plant	112	38	—	—	—	150
Total Accumulated Depreciation.	$1,072,576	$119,283	$49,171	$ 9,417	$12,472	$1,244,085

(1) Principally due to capitalization of leases at December 31, 1980.

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DUKE POWER COMPANY

SCHEDULE VIII—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(Dollars in thousands)

Description	Balance Beginning of Year	Charged To Costs and Expenses	Deductions	Balance End of Year
For the Year Ended December 31, 1980				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$4,131	$3,402	$3,469(1)	$4,064
Other Reserves				
Operating Reserves(3)	$9,531	$3,266	$1,712(2)	$11,085
For the Year Ended December 31, 1979				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$3,608	$3,554	$3,031(1)	$4,131
Other Reserves				
Operating Reserves(3)	$7,604	$3,813	$1,886(2)	$9,531
For the Year Ended December 31, 1978				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$3,053	$3,903	$3,348(1)	$3,608
Other Reserves				
Operating Reserves(3)	$4,876	$3,896	$1,168(2)	$7,604

(1) Uncollectible accounts written off, net of recoveries.

(2) Entries represent payments primarily for injuries and damages in North Carolina and South Carolina.

(3) Consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits," on the Balance Sheets.

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DUKE POWER COMPANY

SCHEDULE X—SUPPLEMENTARY INCOME STATEMENT INFORMATION

	Year Ended December 31		
	1980	1979	1978
	(Dollars in thousands)		
Maintenance of plant facilities	$114,597	$ 94,598	$ 78,605
Taxes, other than payroll and income taxes:			
Real and personal property	32,783	30,736	30,247
State and city franchise	75,264	67,308	61,140
Other	6,208	5,814	5,641
Total	$228,852	$198,456	$175,633

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EXHIBIT I

DUKE POWER COMPANY

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE

This calculation is submitted in accordance with Release No. 9083 under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	Year Ended December 31		
	1980	1979	1978
	(Dollars in thousands, except per share figures)		
Fully Diluted:			
Earnings applicable to common stock(1)	$252,479	$222,198	$183,969
Add: Dividends on Preference Stock, 6¼% Convertible Series AA	1,919	2,564	3,184
Earnings as adjusted for computation	$254,398	$224,762	$187,153
Average common shares outstanding—twelve months (000)	81,985	77,168	70,367
Add: Common shares required for conversion of Preference Stock, 6¼% Convertible Series AA, $100 par, 500,000 shares authorized (208,586 shares outstanding as of December 31, 1980)(2)	873	1,359	1,716
Common shares as adjusted for computation.	82,858	78,527	72,083
Fully diluted earnings per share	$3.07	$2.86	$2.60

(1) These figures agree with the related amounts in the Statements of Income.

(2) The conversion price used to convert the Preference Stock, 6¼% Convertible Series AA, into shares of common stock was $23.89 for 1980 and $24.73 for 1979 and 1978.

PART III.

Item 9. *Directors and Executive Officers of the Registrant.*

Information for this item concerning directors of the Company is set forth in the section entitled "Election of Directors" in the proxy statement of the Company relating to its 1981 annual meeting of shareholders, which is incorporated herein by reference.

Information concerning the executive officers of the Company is set forth on page 19 of this annual report.

Item 10. *Management Remuneration and Transactions.*

Information for this item is set forth in the section entitled "Remuneration of Directors and Officers" in the proxy statement of the Company relating to its 1981 annual meeting of shareholders, which is incorporated herein by reference.

PART IV.

Item 11. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K.*

Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Financial Statements

- Statements of Income for the Three Years Ended December 31, 1980
- Statements of Source of Funds for Plant Construction Costs for the Three Years Ended December 31, 1980
- Balance Sheets—December 31, 1980 and 1979
- Statements of Capitalization—December 31, 1980 and 1979
- Statements of Retained Earnings for the Three Years Ended December 31, 1980
- Notes to Financial Statements

Supplemental Financial Data

Supplemental Schedules

- Schedule V—Property, Plant and Equipment for the Years Ended December 31, 1980, 1979 and 1978
- Schedule VI—Accumulated Depreciation and Amortization of Property, Plant and Equipment for the Years Ended December 31, 1980, 1979 and 1978
- Schedule VIII—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 1980, 1979 and 1978
- Schedule X—Supplementary Income Statement Information for the Years Ended December 31, 1980, 1979 and 1978

Exhibit 1—Computation of Fully Diluted Earnings Per Share

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

Financial statements and schedules of the Company's subsidiaries are omitted because all such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Exhibits

(a) —See Exhibit Index on page 49

(b) —Annual Report on Form 11-K with respect to the Stock Purchase-Savings Program for Employees of the Company for the fiscal year ended October 31, 1980 and the Employees' Stock Ownership Plan for the fiscal year ended December 31, 1980

Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1980

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 in the City of Charlotte and State of North Carolina on the 4th day of March, 1981.

DUKE POWER COMPANY
(Registrant)

By: CARL HORN, JR.
Chairman of the Board

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
CARL HORN, JR.	Chairman of the Board (Principal Executive Officer)	March 4, 1981
W. H. GRIGG	Senior Vice President, Legal and Finance (Principal Financial Officer)	March 4, 1981
PORTER A. HAUSER	Vice President and Controller (Principal Accounting Officer)	March 4, 1981
NAOMI G. ALBANESE D. W. BOOTH THOMAS H. DAVIS ROBERT C. EDWARDS JOHN L. FRALEY ALESTER G. FURMAN III W. H. GRIGG PAUL H. HENSON GEORGE R. HERBERT JOHN D. HICKS HOWARD HOLDERNESS CARL HORN, JR. W. S. LEE BUCK MICKEL REECE A. OVERCASH, JR. WARREN H. OWEN MARSHALL I. PICKENS MACEO A. SLOAN A. C. THIES WILLIAM L. WATKINS	All of the Directors	March 4, 1981

LEWIS F. CAMP, JR., by signing his name hereto, does hereby sign this document on behalf of the issuer and on behalf of each of the above-named persons pursuant to powers of attorney duly executed by the issuer and such persons, filed with the Securities and Exchange Commission as supplemental information.

LEWIS F. CAMP, JR.
Lewis F. Camp, Jr., Attorney-in-fact

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EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit Number	
3-A	—Restated Charter of registrant, dated as of January 1, 1979 (filed with Form S-7, File No. 2-63592, effective March 14, 1979, as Exhibit 2-B-1).
3-B	—Statement of Classification of Shares relating to the 8.84% Cumulative Preferred Stock, Series N (filed with Form S-16, File No. 2-66561, effective February 6, 1980, as Exhibit 2-B-3).
3-C	—Statement of Classification of Shares relating to the 11% Cumulative Preferred Stock, Series O (filed with Form S-16, File No. 2-68582, effective August 19, 1980, as Exhibit 2-B-3).
*3-D	—By-Laws of registrant, as amended to date.
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-3	—Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).
4-B-4	—Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12	—Supplemental Indenture, dated as of April 1, 1951, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13	—Supplemental Indenture, dated as of September 1, 1953, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).

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Exhibit Number

4-B-15 —Supplemental Indenture, dated as of January 1, 1955, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).

4-B-16 —Supplemental Indenture, dated as of May 1, 1956, supplementing said Mortgage (filed with Form S-9, File No. 2-12402, effective April 26, 1956, as Exhibit 2-B-16).

4-B-17 —Supplemental Indenture, dated as of January 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).

4-B-18 —Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).

4-B-19 —Supplemental Indenture, dated as of February 1, 1962, supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).

4-B-20 —Supplemental Indenture, dated as of August 1, 1962, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).

4-B-21 —Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-20).

4-B-22 —Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).

4-B-23 —Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).

4-B-24 —Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).

4-B-25 —Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).

4-B-26 —Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).

4-B-27 —Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).

4-B-28 —Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).

4-B-29 —Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).

4-B-30 —Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effective March 7, 1972, as Exhibit 2-B-30).

4-B-31 —Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).

4-B-32 —Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).

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Exhibit Number	
4-B-33	—Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).
4-B-34	—Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).
4-B-35	—Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).
4-B-36	—Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).
4-B-37	—Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).
4-B-38	—Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).
4-B-39	—Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).
4-B-40	—Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).
4-B-41	—Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).
4-B-42	—Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).
4-B-43	—Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-68571, effective August 19, 1980, as Exhibit 2-B-43).
*4-B-44	—Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage.
4-B-45	—Indenture, dated as of September 1, 1957, between registrant and Chemical Corn Exchange Bank, Trustee, covering 4¼% Sinking Fund Debentures due September 1, 1982 (filed with Form S-9, File No. 2-13526, effective September 4, 1957, as Exhibit 2-B-17).
4-B-46	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Indenture (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-23).
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated as of August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated as of October 14, 1980, between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated as of October 14, 1980, between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

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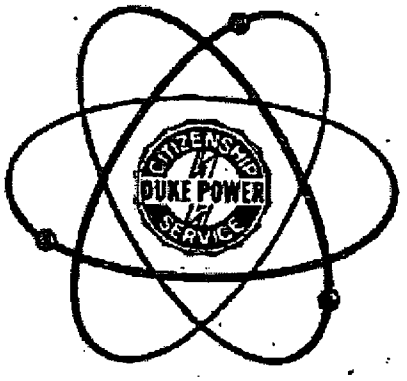

WARNING

FOR ARCHIVES

Do Not Damage Or Destroy

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SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1981 — Commission File Number: 1-4928

Duke Power Company

(Exact name of registrant as specified in its charter)

North Carolina	56-0205520
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
422 South Church Street Charlotte, North Carolina	28242
(Address of principal executive offices)	(Zip Code)

704-373-4579

(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
Preferred Stock, par value $100	
8.70% Series F	New York Stock Exchange
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
8.84% Series M	New York Stock Exchange
8.84% Series N	New York Stock Exchange
11% Series O	New York Stock Exchange
Preferred Stock A, par value $25	
10.76% Series 1975	New York Stock Exchange
Preference Stock, par value $100	
6¾% Convertible Series AA	New York Stock Exchange
First and Refunding Mortgage Bonds	
7¾% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7¾% Series B Due 2002	New York Stock Exchange
7⅞% Series Due 2003	New York Stock Exchange
8⅛% Series B Due 2003	New York Stock Exchange
9¾% Series Due 2004	New York Stock Exchange
9½% Series Due 2005	New York Stock Exchange
8¾% Series Due 2006	New York Stock Exchange
8⅛% Series Due 2007	New York Stock Exchange
9⅜% Series Due 2008	New York Stock Exchange
10⅛% Series Due 2009	New York Stock Exchange
10⅞% Series B Due 2009	New York Stock Exchange
14⅞% Series Due 2010	New York Stock Exchange
14¾% Series Due 1987	New York Stock Exchange
12% Series Due 1990	New York Stock Exchange
13⅛% Series B Due 2010	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, par value $100

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

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at February 11, 1982 ..... $1,649,802,399

Number of shares of Common Stock, without par value, outstanding at February 11, 1982 92,707,586

Documents incorporated by reference:

The registrant has incorporated herein by reference certain sections of its proxy statement relating to the 1982 annual meeting of shareholders to provide information required by the following parts of this annual report:

Part I—Item 4., Security Ownership of Certain Beneficial Owners and Management
Part III—Item 9., Directors and Executive Officers of the Registrant
—Item 10., Management Remuneration and Transactions

DUKE POWER COMPANY

FORM 10-K

ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION FOR THE YEAR ENDED DECEMBER 31, 1981

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PART I.

Item 1. *Business.*

DUKE POWER COMPANY

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,000,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1981, the Company's electric revenues amounted to approximately $1.9 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks ninth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242 (Telephone No. 704-373-4579).

Factors Affecting the Industry. The electric utility industry in general has been experiencing problems in a number of areas including the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities, particularly in the aftermath of the Three Mile Island accident; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; difficulty in obtaining sufficient capital on reasonable terms; difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

For a discussion of the developments affecting the Company, see "Construction Program" (pages 2 through 5), "Business—Rate Matters" (pages 7 and 8), "Business—Fuel Supply" (pages 8 through 10), "Business—Regulation—*Environmental Matters*" (pages 10 through 13) and "Business—Regulation—*Nuclear Facilities*" (pages 13 and 14).

FINANCING PROGRAM

In January 1982 the Company issued 3,727,544 shares of Common Stock in exchange for $119.9 million principal amount of outstanding first and refunding mortgage bonds (the Debt-Equity Exchange). In March 1982 the Company also issued $100 million principal amount of First and Refunding Mortgage Bonds, 15⅛% Series Due 1991 (the New Bonds) and 1.6 million shares of 15.40% Preferred Stock A, 1982 Series (par value $25) (the New Preferred Stock). In addition to the issuance of the New Preferred Stock and the New Bonds, it is contemplated that the Company will borrow in April 1982 the proceeds of the sale in the Eurodollar market of $50 million principal amount of unsecured notes to be issued and sold by the Company's subsidiary, Duke Power Overseas Finance N.V., and unconditionally guaranteed as to payment of principal, interest and premium, if any, by the Company.

The Company presently estimates that it will obtain through the sale of securities and other external sources at least 30% of its 1982-1984 total capital requirements, which include cost estimates of $2.02 billion for the construction program, $514 million for nuclear fuel, $78 million for the refunding of maturing long-term debt and sinking fund requirements and approximately $125 million related to maturities with respect to capitalized nuclear fuel trusts. The balance of such requirements is expected to be obtained from retained earnings, depreciation and amortization, deferred taxes, investment tax credit and other internal sources. Such expectation is based in part upon receiving future rate increases as to which no assurance can be given. The types, amounts and timing of sales of additional securities will depend upon market conditions and other factors. The foregoing estimates of the Company's capital requirements expected to be obtained from external sources assume no sale of any portion of the Company's remaining interest in the Catawba Nuclear Station.

The Company received $521 million in 1981 from the sale of a 75% undivided interest in Unit No. 1 of its Catawba Nuclear Station to groups of its North Carolina and South Carolina rural electric cooperative customers. The proceeds of such sale substantially met the Company's capital requirements for that year. The sale of any further portion of the Catawba Nuclear Station would reduce the amount of external financing

required by the Company by the amount initially received and by the amounts of progress payments to be made as additional construction costs are incurred. As described under "Facilities Under Construction," the Company has reached an agreement to sell a portion of its remaining interest in that Station to a joint agency formed by a group of its South Carolina municipal customers. Should such sale be consummated in mid-1982, the Company anticipates that it would receive approximately $250 million at that time. The Company has no assurance that such sale will be consummated.

In order to issue additional mortgage bonds and preferred stock, the Company must comply with earnings coverage and assets requirements contained in its mortgage indenture and articles of incorporation. Under the provisions of such indenture, additional bonds (other than certain types of refunding bonds) may not be issued unless the Company's available net earnings (as defined) for 12 consecutive calendar months within the 15 calendar months immediately preceding shall have been at least twice the amount of the annual interest charges on all bonds outstanding and applied for under the indenture. Additional bonds may be issued only against cash, certain retired bonds and in the amount of 66⅔% of the aggregate of the net amounts of additional property certified to the trustee pursuant to the indenture.

Under its articles of incorporation, the Company may not issue additional shares of preferred stock unless, after giving effect thereto, (i) its net earnings available for dividends on the preferred stock for any 12 consecutive calendar months within the 15 calendar months preceding the month in which the additional shares are to be issued shall have been at least twice the dividend requirements for a 12-month period upon the entire amount of preferred stock and all other stock ranking prior to or on a parity with the preferred stock, and (ii) the total net assets of the Company at a date not more than 90 days prior to the date on which the additional shares are to be issued shall equal at least twice the aggregate amount payable upon the involuntary liquidation of the Company to the holders of the preferred stock and all other stock ranking prior to or on a parity with the preferred stock.

On the basis of these requirements, the Company's interest and dividend coverages for the years shown were as follows:

	Year Ended December 31		
	1981	1980	1979
Mortgage bond interest	2.61	2.73	3.11
Preferred stock dividends	5.96	5.45	5.28

As of December 31, 1981, after giving effect to the Debt-Equity Exchange and the issuance of the New Bonds, the Company could have issued under the earnings test contained in its mortgage indenture approximately $390 million principal amount of additional bonds. As of such date, after giving effect to the issuance of the New Preferred Stock, the Company could have issued approximately $690 million of additional preferred stock within the restrictions contained in its articles of incorporation.

CONSTRUCTION PROGRAM

Estimated Costs

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rate increases), the availability and cost of capital in the financial markets, the availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise (see "Opposition to Nuclear Power Development") and changing regulatory and environmental standards (see "Business—Regulation—*Environmental Matters*"). The estimates of construction costs and the timing of construction expenditures are also subject to the sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to a joint agency formed by a group of its South Carolina municipal customers. The Company is keeping its construction program as flexible as possible in order to accommodate any variations as a result of such considerations.

Costs for the construction program, including the acquisition of nuclear fuel, for each of 1982, 1983 and 1984 and for the three-year period 1982-1984, as now scheduled, are currently estimated, assuming no further sale of the Company's remaining interest in the Catawba Nuclear Station, as follows (in millions of dollars):

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Type of Facilities	1982	1983	1984	Total
Generation	$474	$445	$322	$1,241*
Transmission	50	60	49	159
Distribution	126	146	182	454
Other	57	64	45	166
Total	$707**	$715**	$598**	$2,020**
Nuclear Fuel	$156	$148	$210	$ 514

* Cost estimates for the three-year period 1982-1984 include approximately $150 million attributable to the portion of the Catawba Nuclear Station which the Company has agreed to sell to a joint agency formed by a group of its South Carolina municipal customers. Such estimates also include approximately $300 million to continue construction activities at the Cherokee Nuclear Station (see "Facilities Under Construction").

** The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation utilizing Bureau of Labor Statistics indices.

The Company is continuing to experience increases in the cost of construction of new facilities as a result of recurring rises in the costs of materials, labor and capital, and increasing capital commitments attributable to more stringent regulatory requirements. However, the Company believes that in recent years it has been able to construct generating units at a lower cost per KW than generally experienced by other utilities for units of comparable type and vintage.

During the three-year period 1979-1981, gross property additions (including nuclear fuel) and net retirements amounted to approximately $2.5 billion and $500 million, respectively, resulting in a net increase of approximately $2.0 billion, or 35%, in gross plant. Net retirements include the portions of the Catawba Nuclear Station sold to certain of the Company's municipal and cooperative customers (see "Facilities Under Construction").

Facilities Under Construction

The following table sets forth the major generating facilities of the Company currently under construction which are to be added to its present generating capability of 13,234,000 KW:

Unit and Location	Net KW Capability	Energy Source	Company Ownership (%)	Date of Planned Operation(1)	Estimated Construction Cost per KW(2)	Total Estimated Construction Costs(2)	Amounts Expended Through December 31 1981(2)
						(Dollars in millions)	
McGuire No. 2 (Northwest of Charlotte, in North Carolina)	1,180,000	Nuclear	100	1983	$ 828	$1,955(3)	$1,642(3)
Catawba No. 1	1,145,000	Nuclear	25	1984	1,279	732(4)	386(4)
Catawba No. 2 (Southwest of Charlotte, in South Carolina)	1,145,000		25	1985			
Cherokee No. 1	1,280,000	Nuclear	100	(5)	(5)	(5)	532
Cherokee No. 2 (Northeast of Spartanburg, in South Carolina)	1,280,000		100				
Bad Creek(6) (Oconee County, South Carolina)	1,000,000	Hydro	100	(6)	861	861	17

(1) Based on past experience, operational dates may vary due to construction delays, difficulties which may be encountered in obtaining regulatory approvals or in obtaining capital at reasonable costs, changes in load forecasts and other factors (see "Business—Regulation").

(2) These amounts exclude the costs of initial fuel cores.

(3) Unit No. 1 of the McGuire Nuclear Station commenced commercial operation on December 1, 1981 (see "Business—Regulation"). The Company prepares cost estimates on a total station basis. Thus,

both estimated construction costs and actual expenditures include all costs related to Unit No. 1 as well as Unit No. 2.

(4) These amounts do not include the costs of the undivided interests sold to the North Carolina Municipal Power Agency Number 1 in 1978 and to groups of the Company's cooperative customers in 1981, and assume no further sale of the Company's remaining interest in the Catawba Nuclear Station. The Catawba construction schedule is now being reviewed and it appears that there will be some delay in planned operation dates which will increase the total estimated construction cost.

(5) Unit Nos. 1 and 2 of the Cherokee Nuclear Station, previously scheduled for completion in 1990 and 1993, respectively, have been delayed indefinitely due to difficulties in attracting the necessary capital on reasonable terms. Work on Unit No. 1 has been substantially reduced and work on Unit No. 2 has been interrupted while the Company fully evaluates its long-term options with respect to such station. Although this delay may result in near-term reductions in costs, cost escalation and inflationary trends will, over the long-term, increase construction costs per KW should this facility be rescheduled and constructed at a later date.

(6) The Bad Creek hydroelectric pumped storage facility will consist of four 250,000 KW units. Although construction completion has not been definitely scheduled, the above cost estimates assume commercial operation dates of 1990 for two units and 1991 for the remaining two units.

In order to reduce its need for external financing, the Company, in 1978, sold to the North Carolina Municipal Power Agency Number 1 (NCMPA), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit No. 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. In 1981, the Company also sold to groups of its North Carolina and South Carolina cooperative customers a 75% undivided interest in Unit No. 1 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. These sales were at cost plus a profit associated with the interests sold. The Company will continue to construct the facility and the purchasers will finance their respective portions of the construction costs by continued monthly progress payments.

The transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The Company will also maintain a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station which could commence, under certain circumstances, this year.

Agreement also has been reached between the Company and a group of its South Carolina municipal customers with respect to the purchase by a joint agency of such customers of the remaining 25% interest in Unit No. 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to the NCMPA. The sale is contingent, however, upon the arrangement of necessary financing by the purchasers. There is no assurance that such proposed sale will be consummated.

During 1981, the NCMPA's participating municipalities, which are presently wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and the proposed purchasers of the balance of Unit No. 2 accounted for approximately 2% of KWH sales and approximately 2% of revenues. The purchasers of a portion of Unit No. 1 accounted for approximately 6% of KWH sales and approximately 5% of revenues.

The application for operating licenses for the Catawba Nuclear Station has been filed by the Company and docketed by the Nuclear Regulatory Commission (NRC). Subsequent to the docketing, the Atomic Safety and Licensing Board granted several petitions to intervene in the licensing proceeding and a hearing will be required.

Load Management

The Company currently is engaged in a comprehensive load management program designed to reduce the growth in peak demand without restricting the continued economic development of the Company's service area. Such program includes, among other things, promotion of energy-efficient building structures and appliances, use of residential conservation rates, use of interruptible rates for large customers, control by the Company (with customers' consent) of residential electric water heaters and air conditioners during peak demand periods and time-of-day pricing to a limited number of customers. The current and planned aspects of such program are designed to reduce the growth in peak demand by approximately 2,426,000 KW in the summer of 1989 and 3,913,000 KW in the summer of 1996 (from estimated peak demands at those times without load management) and to enhance generating reserve margins through the ability to interrupt approximately 687,000 KW of load in 1989 and 1,121,000 KW in 1996. The Company has currently documented reductions through accumulated load management of approximately 774,160 KW for its summer peak load and approximately 1,059,720 KW for its winter peak load.

The Company estimates a minimum reserve margin of approximately 19% of its anticipated peak load requirements through 1984 and approximately 22% from 1984 through 1990. These estimates take into consideration the availability of interruptible loads and the recently revised construction program. (For information about the Company's peak loads, see "Business—Energy Requirements and Capability.")

General

The Company has designed a third unit of the Cherokee Nuclear Station but has not scheduled its construction or exercised its options for the purchase of the major components.

The Board of Directors at its February 1982 meeting approved the withdrawal of the Company's application for a construction permit for the proposed Perkins Nuclear Station. The Company intends to request permission in each of its regulatory jurisdictions to recover costs related to such facility. The Company has incurred no material costs and has no commitments the cancellation of which would result in any material costs with respect to such facility.

The complexity of present-day electric utility technology and the time required for the construction of generating facilities and for the completion of the licensing and other regulatory proceedings relating thereto have compelled the Company, as well as other electric utilities, to make substantial investments in the construction of such facilities prior to the completion of licensing and regulatory proceedings. At December 31, 1981, the Company had incurred costs of approximately $1.6 billion for the Catawba and Cherokee Nuclear Stations and Unit No. 2 of the McGuire Nuclear Station, for which only construction permits had been issued. Under present NRC procedures, an operating license may be issued only when construction of a nuclear unit has been completed. Accordingly, the Company is necessarily making substantial investments in its facilities before regulatory proceedings are completed. There is no assurance that the necessary operating licenses and authorizations will be issued for such facilities.

Opposition to Nuclear Power Development

The development of nuclear power continues to be a subject of public controversy, particularly in the aftermath of the Three Mile Island accident (see "Business—Regulation—*Nuclear Facilities*"). Various groups have engaged in public protests, filed suits and participated in administrative proceedings and other activities, claiming that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. In addition, restrictive legislation relating to nuclear power has been proposed in Congress and in several state legislatures and referenda have been proposed to the electorate in certain states. Some of the claims made by such groups, if they should prevail, or the existence of the controversy itself, could delay or prevent the construction of nuclear generating units presently planned or under construction, or cause substantial modifications to or shutdowns of existing units.

The Company's studies continue to support its conclusion that the generation of electricity by nuclear power will be more economical than generation by fossil fuel, and the Company believes that its present construction program is compatible with the protection of the environment.

BUSINESS

Service Area

The Company supplies electric service directly to approximately 1,307,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to 37 other incorporated municipalities and to a number of rural electric cooperatives and private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco, furniture and chemical industries are of major significance to the economy of the area, and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, food products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $293 million of the Company's revenues for 1981, representing 16% of electric revenues and 48% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1981, its generation of electric energy for 1981, and certain corresponding information presently projected for 1982:

			Generating Capability(1)			Generation		
			Actual December 31, 1981		Projected 1982(2)	Actual 1981		Projected 1982(2)
Source	Facility		KW	%	%	KWH (millions)	%	%
Coal	Belews Creek		2,240,000			14,413		
	Marshall		1,900,000			12,910		
	Allen		1,100,000			5,090		
	Cliffside		770,000			4,040		
	Others		1,413,000			6,060		
		Total	7,423,000	56.1	56	42,513	73.6	67
Nuclear	Oconee		2,580,000			13,823		
	McGuire		1,180,000			406(3)		
		Total	3,760,000	28.4	28	14,229	24.6	30
Hydro	26 stations		1,452,000	11.0	11	843	1.5	3
Oil and Gas	Combustion turbines		599,000	4.5	5	146	0.3	—
		Total	13,234,000	100.0	100	57,731	100.0	100

(1) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(2) Projected figures are based on the assumption that required fuel is available and that there are no unforeseen contingencies.

(3) Includes generation of 387 million KWH prior to commercial operation.

According to industry statistics through 1980, the Company ranked first in the nation for the last seven consecutive years and for nine of the last eleven years in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. While the 1981 company rankings have not been published, initial station reports indicate that Marshall and Belews Creek Steam Stations were the first and second most efficient in the nation in 1981. A Company station has been ranked first in efficiency in 14 of the last 16 years through 1981. Statistics supplied to the NRC by utilities demonstrate that the Company's Oconee Nuclear Station was the most efficient nuclear facility in the nation in 1981. The net capacity factors for the Oconee Nuclear Station were 63% for both 1979 and 1980 and 61% for 1981.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1981-1982 winter peak load of 11,145 MW occurred on January 11, 1982, and the 1981 summer peak load of 10,602 MW occurred on August 5, 1981. The 1980-1981 winter peak load of 10,530 MW occurred on January 12, 1981, and the 1980 summer peak load of 10,364 MW occurred on July 16, 1980.

Federal Energy Legislation

Congress adopted a national energy act in 1978 dealing with, among other things, utility rate design, including restrictions on the use of fuel adjustment clauses. Other sections of the legislation give FERC increased authority to order interconnections, power pooling and wheeling of power. The Company is presently unable to assess the impact of this legislation on its operations.

Rate Matters

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSC) must approve the Company's rates for retail sales within the respective States. The Federal Energy Regulatory Commission (FERC) must approve the Company's rates for sales under its wholesale rate schedules.

General Rate Increases. The following table sets forth information concerning all rate increases requested or implemented by the Company since January 1, 1979. The revenues (in millions of dollars) shown are annualized on the basis of the filing test year.

Jurisdiction and Date Filed	Requested Revenues	Approved Revenues	Approved % of Request	Approved % of Increase Over Previous Revenues	Rate Order Effective(1)	End of 12-Month Test Period
N. C. Retail:						
March 1979	$ 35.5	$ 28.3	79.7	3.2	October 1979	December 31, 1978
February 1980	91.6	57.5	62.7	6.0	October 1980	December 31, 1979
March 1981	211.0	166.4	79.0	14.99	December 1981	December 31, 1980
S. C. Retail:						
August 1979(2)	25.8	23.4	90.5	6.0	September 1980	June 30, 1979
December 1980	103.7	57.0	54.9	13.0	January 1982	December 31, 1980
February 1982	99.5	—	—	—		
FERC Wholesale:						
June 1980(3)	26.3	18.6	70.7	8.9	February 1981	December 31, 1981
June 1981(4)	46.9	—	—	—		

(1) In the past, the Company has collected interim rate increases, subject to refund, in all three jurisdictions and is currently collecting on that basis from its wholesale customers. On occasion the Company has implemented its entire request on such a basis prior to the final rate order.

(2) Intervenors appealed this order to the Court of Common Pleas, Richland County, in October 1980 on various grounds and are seeking its reversal or modification and refunds of amounts paid to the Company pursuant to its provisions.

(3) This increase was based on an agreement that allows the Company to maintain general parity between rates for its wholesale customers and rates for its North Carolina retail industrial customers.

(4) This request was based on a concept that allows the Company to maintain general parity between rates for its wholesale customers and rates for its North Carolina retail industrial customers. The Company is negotiating with its wholesale customers with regard to continuing the parity concept.

The Company has not been able to earn the rates of return as allowed and defined by the NCUC and the PSC in recent rate proceedings since orders resulting therefrom were based on historical cost during inflationary periods. In the Company's most recent rate proceedings, the NCUC allowed a jurisdictional rate of return on common equity of 16.5%, and the PSC allowed a jurisdictional rate of return on common equity of 13%.

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The Company intends to file an application for an additional retail rate increase in North Carolina in the near future and an application for an additional wholesale rate increase by mid-year.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The procedures for wholesale customers entail a 90-day lag from the date changes in fuel expense occur until they are reflected in bills to such customers.

Beginning February 1, 1980, the procedures for North Carolina retail customers were modified to set the base fuel factor on a prior four months' experience and to limit changes in this factor to four-month intervals. The NCUC will review the operation of the Company's base load generating facilities if its nuclear units generate at a capacity factor of less than 60%, in which event the Company has the specific burden of justifying the recovery of its incremental fuel costs. The NCUC has scheduled hearings in June 1982 to consider the adequacy of the current fuel cost recovery procedures.

Effective June 1, 1979, the fuel cost recovery procedures for South Carolina retail customers were modified to set the base fuel factor semiannually after a public hearing to review fuel costs. The semiannual review takes into consideration fuel costs experienced during the preceding six months as well as fuel costs projected for the subsequent six months.

Fuel Supply

The Company presently relies principally on coal for the generation of electric energy, but it anticipates relying on nuclear power to a greater extent in the future (see "Construction Program"). The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source			Average Cost per Million BTU on a Burned Basis		
	Year Ended December 31			Year Ended December 31		
	1981	1980	1979	1981	1980	1979
Coal	73.6%	71.6%	68.5%	178.39¢	155.64¢	148.86¢
Nuclear	24.6	24.8	26.1	48.98	48.22	38.51
Oil and Gas	.3	.4	.3	416.17	300.16	246.16
All Fuels (cost based on weighted average)	98.5	96.8	94.9	144.33	127.00	116.81
Hydroelectric*	1.5	3.2	5.1			
	100.0%	100.0%	100.0%			

* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

Coal. The Company obtains its coal under long-term supply contracts with mining operators utilizing both deep and surface mining, through its own mining operations, all of which are deep mine, and by open market purchases. During 1981, the Company obtained its coal requirements approximately as follows: 69% (10.9 million tons) under long-term contracts, 12% (2.0 million tons) from its own mining operations and 19% (3.0 million tons) by open market purchases.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1982 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. In order to further assure its coal supply, the Company has invested in independent coal mining operations located in eastern Kentucky.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. The Company purchased coal on a spot basis at an average delivered cost of $42.60 per ton, or 176.1¢ per million BTU, during 1981, as compared with an average delivered cost of $33.80 per ton, or 139.9¢ per million BTU, during 1980.

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The following table sets forth the Company's estimated recoverable coal reserves from its own mining operations:

Estimated Recoverable Coal Reserves

As of December 31, 1981

(In Thousands of Tons)

State and Mine Location	Total	Average % Sulfur
Kentucky		
Eastover No. 1 (Highsplint)	64,900	0.9
Eastover No. 2 (Brookside)	29,600	0.9
Eastover No. 4 (Arjay)	48,700	1.2
Kentucky Border	18,400	1.0
	161,600	
Virginia		
Eastover No. 6 (Virginia City)	24,400	0.9
	186,000	

Such reserves represent the amounts of coal that can be expected to be recovered by underground mining from total coal reserves "in place" after allowing for unavoidable coal losses during mining and cleaning operations and for coal necessarily left in place for safety and other purposes. An overall recovery factor of 74.4% was used. The reserves lie within 2,500 feet from a known seam measurement, but exclude rock partings within the seams, seams of less than 30-inch thickness with minor exceptions, or other areas judged impractical to mine. The sulfur content of seams currently being mined at Eastover No. 4 (Arjay) is about 2.25% which is blended with a lower sulfur coal and used as a fuel. New seams planned for mining at that location beginning in 1982 are expected to average 1.5% sulfur.

Additional coal tonnage of similar quality has been established at the Company's mining operations, but a determination of the degree to which this coal could be commercially mineable would require further evaluation which the Company does not intend to undertake at this time.

Federal legislation relating to the regulation of surface mining of coal was enacted in 1977. Such legislation, among other things, establishes standards restricting the surface mining of coal, requires the restoration of lands affected by surface mining and imposes a tax based upon the tonnage of coal mined to be used for the restoration of abandoned areas. This legislation is adversely affecting the price of coal to the Company. It is anticipated that in 1982 approximately 40% of the Company's coal supply will be provided through surface mining operations.

On March 18, 1982, the Company had on hand a coal supply of approximately 60 days and is endeavoring to increase its inventory.

The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the emission limitation for sulfur dioxide of 2.3 pounds per million BTU of heat input for existing facilities (see "Regulation—*Environmental Matters*").

The Company estimates that through the year 2000 its existing coal-fired generating units (see table under "Energy Requirements and Capability") will burn a total of approximately 270.7 million tons of coal. The Company presently expects to obtain approximately 16% of this estimated requirement from its own mining operations and has long-term agreements which, upon renewal as needed, would substantially provide the balance.

The Economic Regulatory Administration of the Department of Energy is authorized, under prescribed conditions, to allocate coal to achieve, among other things, the distribution of available low sulfur fuels on a priority basis to areas designated by the United States Environmental Protection Agency (EPA).

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride,

enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations (see "Energy Requirements and Capability" and "Construction Program") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1993	1990	2009	1989
McGuire	1993	1990	2009	1989
Catawba	1993	1990	2009	1989

Approximately 75% of the Company's commitments for uranium materials included in the preceding table is expected to be obtained from Rio Algom, Ltd., a Canadian supplier. Deliveries to the Company by such supplier, which began in 1981, are subject to permits and export licenses from various Canadian governmental agencies, including the Atomic Energy Control Board, the Department of Industry, Trade and Commerce and the Uranium Exports Review Panel.

The Company purchased uranium material during 1981 at an average price of approximately $33 per pound. However, such price is expected to be substantially greater in future years. The Company's material nuclear supply contracts generally contain *force majeure* provisions and provide for price escalation under certain conditions.

As a part of the Company's efforts to obtain additional sources of uranium at a reasonable cost, a wholly-owned subsidiary of the Company, Western Fuel, Inc., has entered into a joint venture in central Wyoming with Ogle Petroleum Inc., which is acting as operator. Such venture has established the feasibility of an unconventional method for extracting uranium ore and has completed construction of the first phase of a commercial processing plant. Western Fuel's share of the cost of the plant, to be completed in the latter part of 1982, is estimated to be approximately $7 million. The joint venture has a source materials license from the NRC required for full-scale commercial operation.

The Company has expended approximately $11 million to date in connection with this venture which includes Western Fuel's share of the cost of the first phase of the commercial processing plant. The amount of uranium presently estimated to be available from the project for the Company's use as a percentage of its presently estimated requirements over the life of the project is approximately 5%.

Although the reprocessing of spent fuel could make available to the Company an additional 20% of its nuclear fuel needs through 1990, there are currently no commercial reprocessing facilities in operation in the United States. The utilization of such facilities is dependent upon certain regulatory and policy decisions to be made by the Federal government.

The Company has recently received regulatory approvals which will enable it to provide adequate storage facilities for its spent nuclear fuel through 1989. The Company is also enlarging the capacity of the spent fuel pool at the Catawba Nuclear Station to accommodate larger amounts of spent fuel.

See "*Depreciation and Amortization*" under note 1 of Notes to Financial Statements for additional information regarding nuclear fuel costs.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC and EPA and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities (see "Construction Program"). The coal mining operations of Eastover Mining Company, the Company's coal mining subsidiary, are subject to the Federal Mine Safety and Health Act of 1977.

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation

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existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1982-1984 construction program includes costs for environmental protection (as now defined by EPA) which are estimated to be approximately $178 million, including $53 million in 1982 and $69 million in 1983. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

AIR QUALITY. In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing standards limiting such emissions which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans.

With respect to particulate emissions, the implementation plans require compliance with an opacity standard based on the visual density of the flue gas and a mass emissions standard stated in terms of pounds per million BTU of heat input.

Although the Company believes it has installed the best available control technology in its coal-fired generating stations, it has determined that it could not consistently and continuously meet the stringent mass emission standards of the North Carolina implementation plan even though each unit had successfully completed stack performance tests. The Company filed for a variance from the particulate emission limitations, which was granted by the North Carolina Environmental Management Commission in June 1979 and approved by EPA in August 1980 as a revision to the State's implementation plan. In granting the variance for a three-year period, such Commission found that the Company had installed the best available control technology at its coal-fired generating stations and that independent air monitoring and modeling studies indicated that the emission limitations could be modified without violating state and Federal ambient air quality standards. The Commission also required that extensive performance tests be completed to determine if a correlation exists between opacity and mass emission standards and to provide data for the setting of a permanent mass emission standard. Under the variance, the interim mass emission standard ranges from 0.20 to 0.25 pounds per million BTU of heat input. The Company has submitted to the State the data resulting from the performance test program and believes the State will utilize the data in setting a permanent mass emission standard.

In 1981, EPA approved a revision to the North Carolina implementation plan which eliminated a previously planned stepdown in the opacity limit for existing coal-fired generating units from 40% to 20%.

Following public notice and hearing, the North Carolina Environmental Management Commission approved a revision to the North Carolina regulation in 1977 limiting emissions of sulfur dioxide from fuel-burning sources and submitted the revision to EPA for review and approval as required by the 1970 Act. The revision to the North Carolina State Implementation Plan eliminated a stepdown in the emission limit from 2.3 pounds to 1.6 pounds per million BTU of heat input which had been previously planned for July 1, 1980. To date, EPA has not decided whether to approve or disapprove the revision. However, EPA has indicated that it will not enforce the 1.6-pound limit until final agency action is completed on the pending revision. If EPA disapproves the revision, the Company could be compelled to incur large capital costs for pollution control equipment in order to avoid noncompliance penalties.

In 1974, EPA issued regulations, applicable to the construction or expansion of facilities commenced after June 1, 1975, establishing a mechanism for "prevention of significant air quality deterioration" in areas where air pollution levels of sulfur dioxide and particulate matter are below the national ambient air quality standards. Amendments to the 1970 Act, adopted in 1977, include, among other things, requirements substantially similar to such regulations. The amendments also require EPA to establish stringent restrictions on emissions in non-attainment areas, to update new source performance standards for specified pollutants and to require the use of the best available technology rather than clean fuels to control emissions. The amendments also authorize EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and new civil penalties of up to $25,000 per day for facilities found to be in violation of an applicable implementation plan. EPA has promulgated new source performance standards under these amendments which will apply to all stations not presently under construction and will require the use of scrubbers to remove sulfur dioxides, as well as other techniques to

remove nitrogen oxides and particulate matter emissions. These amendments and proposed standards will affect the lead time, size and siting of future fossil-fueled generating stations as well as the type, complexity and cost of pollution control equipment to be used.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1972 (the 1972 Act) provided for the imposition of effluent limitations to regulate discharges of pollutants, including heat, into the waters of the United States. The 1972 Act mandated that there be achieved by July 1, 1977, with respect to existing facilities, effluent limitations requiring application of the "best practicable control technology currently available" as well as compliance with state water quality standards. The Company has complied with these requirements. Regulations proposed under the 1972 Act also prescribed that the location, design and construction of cooling water intake structures reflect the "best technology available for minimizing environmental impact."

The 1972 Act required permits to ensure compliance with its provisions. The Company has received such permits for all of its generating stations either from EPA or under the permit programs of the States of North Carolina and South Carolina which have been approved by EPA.

In 1974, EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines required certain limitations on chemical discharges and imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit *(Appalachian Power Company, et al., v. Train)*. In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement and certain chemical limitations. The Company is unable at this time to determine what effect these developments will have on its operations.

In 1977, Congress adopted the Clean Water Act of 1977 (the 1977 Act) which amended the 1972 Act. The 1977 Act provided for three categories for controlling pollution: (1) conventional pollutants will require treatment by the best conventional pollutant control technology by July 1, 1984; (2) toxic pollutants will require application of the best available technology economically achievable by July 1, 1984; and (3) non-conventional pollutants will require application of the best available technology economically achievable within three years after effluent limitations are established, but no later than July 1, 1987. The Company will be unable to determine the effect, if any, such legislation will have on its operations until the required regulations are promulgated.

On January 29, 1982, the District Court for the District of Columbia issued a decision (*National Wildlife Federation v. Castle*) declaring that the 1972 Act requires permits for dams that discharge pollutants. The court ordered EPA to adopt final regulations governing such discharges within 90 days. Under the Court's ruling, the Company may be required to obtain discharge permits for its hydroelectric installations that may necessitate costly design or operating changes. The Company, along with EPA, has filed a motion for a stay pending appeal. The court has not ruled on the motion.

OTHER ENVIRONMENTAL REGULATIONS. North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. South Carolina has also adopted regulations implementing its Hazardous Waste Management Act. The Company is in compliance with such Act and the regulations promulgated thereunder.

Polychlorinated biphenyls (PCBs) are regulated by provisions of the Toxic Substances Control Act. Major portions of the regulations issued by EPA implementing such provisions were set aside by the U. S. Court of Appeals for the District of Columbia. The Court stayed its mandate for 18 months from April 1981 to undertake a rulemaking procedure concerning the use of PCBs in electrical equipment. During this period, the existing PCB regulations remain in effect with the additional requirement that certain inspection and maintenance procedures for transformers containing 50 parts per million of PCBs or greater, known as the Interim Measures Program, be implemented. The Company has implemented an Interim Measures Program and is in compliance with the Court's order.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, known as "Superfund" became law in December 1980. It requires the reporting of releases of hazardous substances into the environment and the notification to EPA of hazardous waste facilities which are not subject to other regulations. The Company has implemented reporting procedures in order to comply with the Act.

GENERAL. The Company cannot estimate the effect of existing and potential regulations upon any of its existing and proposed facilities. However, developments in these and other areas of regulation have in the past required the Company to modify or replace equipment and may in the future delay construction and operation of new or existing facilities at costs which could be substantial.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations currently permit public intervention with respect to issuances of permits and licenses.

On May 26, 1981 the Atomic Safety and Licensing Board authorized issuance of an operating license for the McGuire Nuclear Station and on July 8, 1981 the NRC issued a full power operating license for Unit No. 1. An intervenor, Carolina Environmental Study Group, has appealed the ASLB decision to the Atomic Safety and Licensing Appeal Board and the appeal is presently pending.

In March 1979, Unit No. 2 of the Three Mile Island Nuclear Station, owned by another electric utility and located near Harrisburg, Pennsylvania, experienced severe operating difficulties resulting in the shutdown of the Unit and undetermined damage to the reactor core. The nuclear steam supply system of such Unit is of Babcock & Wilcox Company design and manufacture as are those of the three units of the Company's Oconee Nuclear Station (see "Energy Requirements and Capability"). The nuclear steam supply systems of the Company's other nuclear generating facilities in operation, under construction or in the planning stage are of a different design and manufacture.

As a result of the Three Mile Island accident, the NRC has developed an extensive list of requirements for the operation of nuclear facilities. In 1980, the NRC issued an order requiring the Company to implement certain of such requirements at its three Oconee units or to shut down the units. The Company has completed the implementation of such requirements. Other longer term requirements are to be complied with prior to July 1, 1982. These include physical modifications of the units, additional analyses, changes in operating procedures and changes in staffing and training. The Company expects to complete the modifications as required.

The Company cannot predict what other effects the Three Mile Island accident or new NRC rules may have upon it, upon its ability to finance, upon the construction, licensing, cost or future operations of its nuclear units, or upon the Price-Anderson Act and the nuclear liability system.

During a scheduled outage of Unit No. 1 of the Oconee Nuclear Station in 1981 for refueling and required 10-year inspection procedures, the Company discovered that some of the bolts securing the thermal shield in the reactor vessel had failed. Although this condition was not of immediate safety concern, the redesign and replacement of the bolting system extended the outage six weeks. During planned outages of Unit Nos. 2 and 3 in 1982, the Company intends to replace the thermal shield bolting system, conduct 10-year inspection procedures and refuel the Units. It is expected that these steps will cause such Units to be out of service for approximately 120 days.

The NRC recently requested the Company to examine its Oconee reactor vessels for thermal shock effects of emergency core cooling system operations during a loss of feedwater event, as well as other transients which might induce rapid overcooling of the system. Preliminary analyses of the Oconee units conducted by the Company and the manufacturer, Babcock & Wilcox Company, have indicated that the vessels as constructed are adequate to permit safe operation for the remainder of their projected 40-year lives. The present position of the staff of the NRC is that the units can operate safely pending completion of its analysis of the matter. However, should modification be warranted upon completion of analyses, the cost of such modification is not expected to be material.

Vibration problems involving steam generator tubes near the feedwater inlet have been experienced recently in two European units of a structure and design similar to Unit No. 1 of the McGuire Nuclear Station. Slight evidence of wear has been found on four of the more than 18,000 tubes in such Unit. This Unit will be operated at less than full load until the Company and the manufacturer, Westinghouse Electric Corporation, evaluate the situation and implement corrective measures.

The Company has insured against public liability claims resulting from nuclear incidents by purchasing the maximum available private insurance of $160 million, and the remaining $400 million of the $560 million limit on liability under the Price-Anderson Act has been provided by an indemnity agreement with the NRC.

Effective in 1977, the NRC's indemnity began to be phased out in favor of a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors, and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance and indemnity coverage do not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $450 million, or the insurable value of the facilities, whichever is less. The Company anticipates purchasing from Nuclear Electric Insurance Limited (NEIL), a Bermuda mutual insurance company, of which it is a member, an additional $500 million of property damage insurance through its Excess Property Insurance Program. In connection with the sale in 1978 of a portion of its interest in the Catawba Nuclear Station (see "Construction Program"), the Company placed through a pool of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of the maximum coverage available, presently $450 million.

NEIL also provides insurance against the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. The Company's Oconee Nuclear Station is insured for up to $2.3 million a week per unit, after a 26-week deductible period, with declining amounts per unit where more than one unit is involved. Coverages continue at 100% for 52 weeks and at 50% for an additional 52 weeks. This is presently the maximum amount of coverage available.

Reference is made to note 11 of Notes to Financial Statements for information concerning potential retrospective premium adjustments.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which the Company considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

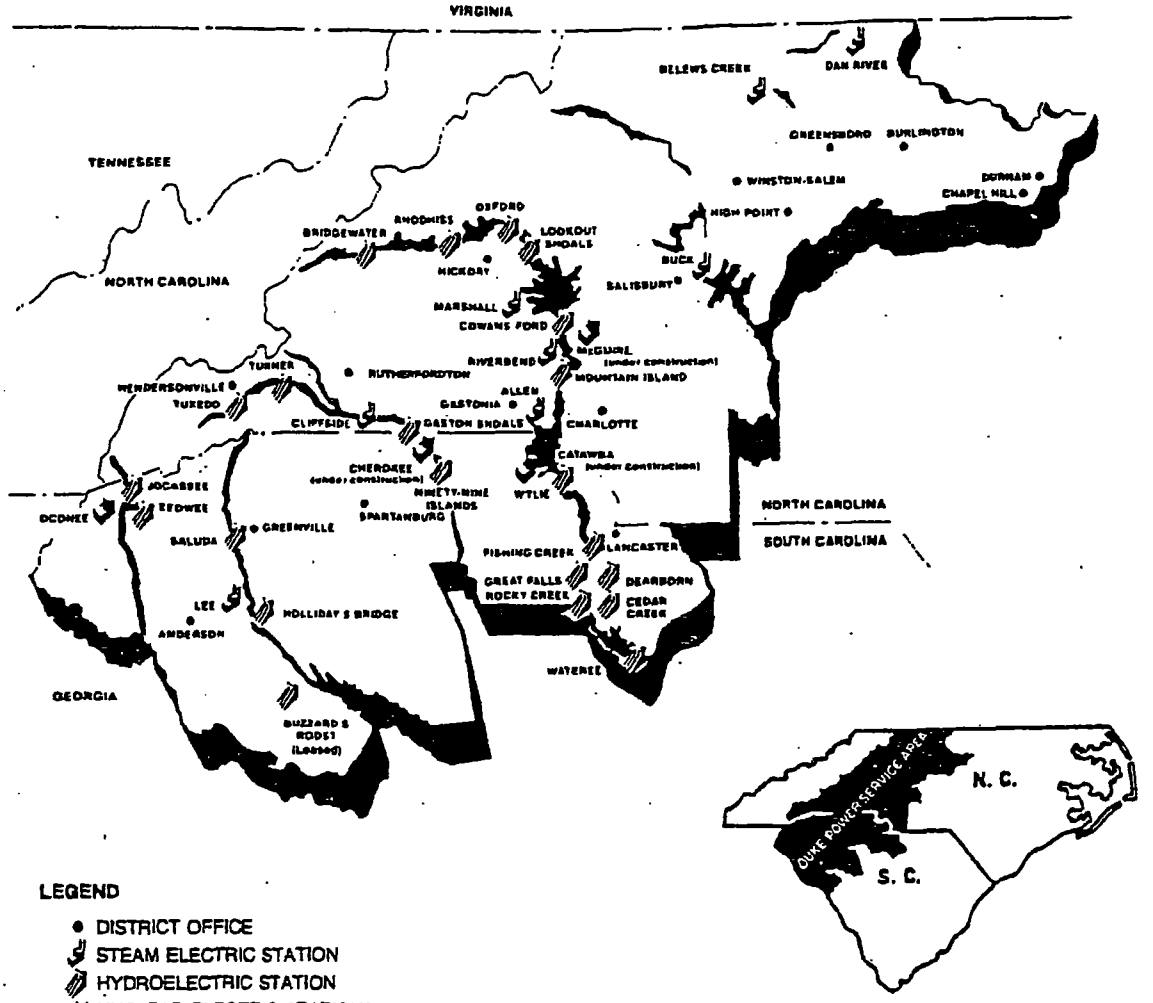
The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

Employees

At December 31, 1981, the Company employed approximately 20,000 persons, of whom approximately 8,000 were engaged in generating plant construction including design and engineering. About 1,850 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW) with which the Company has a labor agreement which expires on September 30, 1982.

The Company's coal mining subsidiary, Eastover Mining Company, employs approximately 1,200 persons, the majority of whom is represented by labor unions, including the United Mine Workers of America.

Duke Power Service Area



LEGEND

- DISTRICT OFFICE
- STEAM ELECTRIC STATION
- HYDROELECTRIC STATION
- NUCLEAR ELECTRIC STATION*

* McGuire Unit 1 complete
McGuire Unit 2 under construction

OPERATING STATISTICS

	Year Ended December 31				
	1981	1980	1979	1978	1977
Sources of Electric Energy—					
Millions of kilowatt-hours:					
Generated—net output:					
Coal	42,513	40,984	37,404	34,589	37,184
Nuclear	14,229	14,213	14,228	15,905	13,008
Hydro	843	1,820	2,809	1,941	1,852
Oil and gas	146	203	163	484	303
Total generated	57,731	57,220	54,604	52,919	52,347
Net interchange and purchased power	494	(472)	(512)	1,016	31
Losses and company use	(4,677)	(4,437)	(3,769)	(3,996)	(3,530)
Total energy sales	53,548	52,311	50,323	49,939	48,848
Average Cost Per Ton of Coal Burned	$43.24	$37.85	$35.86	$34.24	$30.00
Electric Energy Sales—					
Millions of kilowatt-hours:					
Residential	13,861	13,765	12,832	12,959	12,462
General service	9,731	9,395	8,778	8,920	8,623
Industrial	20,667	20,060	20,260	19,523	19,188
Wholesale and other energy sales	9,289	9,091	8,453	8,537	8,575
Total energy sales	53,548	52,311	50,323	49,939	48,848
Electric Revenues—					
Thousands of dollars:					
Residential	$ 624,986	$ 565,633	$ 499,936	$ 469,389	$ 424,081
General service	386,141	340,691	303,858	284,752	256,439
Industrial	613,919	534,790	508,605	448,550	402,003
Wholesale and other energy sales	270,623	232,506	201,938	188,428	173,832
Other electric revenues	12,785	9,202	(21,780)	5,601	10,619
Total electric revenues	$1,908,454	$1,682,822	$1,492,557	$1,396,720	$1,266,974
Number of Customers End of Year—					
Residential	1,125,371	1,105,035	1,078,419	1,049,543	1,024,712
General service	167,282	165,522	161,833	159,538	155,716
Industrial	7,723	7,588	7,475	7,231	6,947
Wholesale and other energy sales	6,326	6,260	5,950	5,857	5,688
Total customers	1,306,702	1,284,405	1,253,677	1,222,169	1,193,063
Residential Customer Statistics—					
Average number for year	1,118,534	1,095,933	1,068,194	1,039,275	1,016,482
Average annual use—KWH	12,392	12,560	12,013	12,469	12,260
Average annual billing	$558.75	$516.12	$468.02	$451.65	$417.20
Average Annual Billed Revenue Per KWH—					
Residential	4.51¢	4.11¢	3.90¢	3.62¢	3.40¢
General service	3.97¢	3.63¢	3.46¢	3.19¢	2.97¢
Industrial	2.97¢	2.67¢	2.51¢	2.30¢	2.10¢
Wholesale and other energy sales	2.91¢	2.56¢	2.39¢	2.21¢	2.03¢

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age*
Carl Horn, Jr.**	Chairman of the Board and Chief Executive Officer	1976	60
W. S. Lee**	President and Chief Operating Officer, and Director	1978	52
D. W. Booth**	Executive Vice President and Director	1976	57
W. H. Grigg**	Senior Vice President, Legal and Finance, and Director	1975	49
A. C. Thies**	Senior Vice President, Production and Transmission, and Director	1971	60
John D. Hicks**	Senior Vice President, Public Affairs, and Director	1977	58
W. H. Owen**	Senior Vice President, Engineering and Construction, and Director	1978	55
Thomas C. Berry	Vice President, Southern Division	1976	51
J. Kenneth Clark	Vice President, Corporate Communications	1981	49
L. C. Dail	Vice President, Design Engineering	1978	56
Donald H. Denton, Jr.	Vice President, Marketing	1975	44
Robert L. Dick	Vice President, Construction	1971	54
George W. Ferguson, Jr. ..	Vice President and Deputy General Counsel	1982	49
Steve C. Griffith, Jr.	Vice President and General Counsel	1977	48
M. T. Hatley, Jr.	Vice President, Rates	1979	59
Porter A. Hauser	Vice President and Controller	1980	64
E. N. Hedgepeth, Jr.	Vice President, Distribution Engineering, Construction and Operations	1978	54
Frank A. Jenkins	Vice President, Transmission	1971	62
S. T. Lattimore	Vice President, Computer Services	1979	55
John F. Lomax	Vice President, Western Division	1980	42
Joe S. Major, Jr.	Vice President, Personnel	1971	61
Joseph G. Mann	Vice President, Northern Division	1973	58
Paul H. Mann, Jr.	Vice President, Operation	1978	59
Paul G. Martin	Vice President, Eastern Division	1982	49
Dwight B. Moore	Vice President, Central Division	1980	60
Henry L. Cranford	Vice President, Division Operations	1980	54
William O. Parker, Jr.	Vice President, Steam Production	1974	57
Richard R. Pierce	Assistant to the Chairman	1979	59
William R. Stimart	Vice President, Regulatory Affairs	1979	50
Fred E. West, Jr.	Vice President, Charlotte Division	1981	45
James W. White	Vice President, General Services	1979	56
Lewis F. Camp, Jr.	Secretary	1980	53
Richard J. Osborne	Treasurer	1981	31

* As of March 1982.

** Members of the Executive Committee.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years except for J. Kenneth Clark who served as Public Affairs Director of Mass. Inst. of Technology from July 1978 to Dec 1981, when he joined the Company as Vice President Corporate Communications. Previously he was Public Affairs Director of Monsanto Company, an industrial chemical manufacturer, from 1976 to 1978.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

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Item 2. *Properties.*

The map on page 15 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V—Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see Item 1.—"Construction Program—Facilities Under Construction" and "Business—Fuel Supply".

Item 3. *Legal Proceedings.*

Reference is made to Item 1.—"Construction Program" and "Business—Regulation" for information relating to licensing proceedings before the Nuclear Regulatory Commission with respect to the Company's nuclear generating facilities.

Reference is made to Item 1.—"Business—Rate Matters" regarding appeals taken from an order of The Public Service Commission of South Carolina and pending proceedings before The Public Service Commission of South Carolina and the Federal Energy Regulatory Commission.

Item 4. *Security Ownership of Certain Beneficial Owners and Management.*

Information for this item is set forth in the sections entitled "Voting Securities Outstanding" and "Security Ownership of Management" in the proxy statement of the Company relating to its 1982 annual meeting of shareholders, which is incorporated herein by reference.

PART II.

Item 5. *Market for the Registrant's Common Stock and Related Security Holder Matters.*

The Common Stock of the Company is traded on the New York Stock Exchange. At February 11, 1982, there were approximately 124,000 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by *The Wall Street Journal* as composite transactions:

Common Stock	Dividends per Share	Price Range	
		High	Low
1981 by Quarter			
Fourth	$0.55	22½	19⅝
Third	0.51	21¼	18¾
Second	0.51	20⅛	17⅛
First	0.51	19¼	15⅞
1980 by Quarter			
Fourth	0.51	18¾	15½
Third	0.48	18⅞	16⅛
Second	0.48	19¼	15⅜
First	0.48	18⅜	14⅛

Reference is made to note 3 of Notes to Financial Statements for information concerning restrictions on the ability of the Company to pay dividends on shares of its Common Stock. At the date hereof, none of the Company's retained earnings was restricted with respect to the declaration or payment of dividends.

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Item 6. *Selected Financial Data.*

DUKE POWER COMPANY

SELECTED FINANCIAL DATA

	1981	1980	1979	1978	1977
	(Dollars in thousands, except per share figures)				
CONDENSED STATEMENTS OF INCOME					
Electric revenues	$1,908,454	$1,682,822	$1,492,557	$1,396,720	$1,266,974
Electric expenses	1,632,104	1,402,722	1,238,680	1,159,719	1,037,088
Electric operating income	276,350	280,100	253,877	237,001	229,886
Other income	254,043	208,365	168,612	131,899	96,955
Income before interest deductions	530,393	488,465	422,489	368,900	326,841
Interest deductions, net	194,142	177,374	147,729	138,299	134,492
Net income	336,251	311,091	274,760	230,601	192,349
Dividends on preferred and preference stocks	57,895	58,612	52,562	46,632	38,879
Earnings for common stock	$ 278,356	$ 252,479	$ 222,198	$ 183,969	$ 153,470
RATIO OF EARNINGS TO FIXED CHARGES (SEC Method)	2.73	2.65	2.86	2.91	2.71
COMMON STOCK DATA					
Shares of common stock					
—End of year (thousands)	88,483	86,294	79,489	72,132	65,430
—Average (thousands)	87,313	81,985	77,168	70,367	63,630
Per share of common stock					
Earnings	$3.19	$3.08	$2.88	$2.61	$2.41
Dividends	$2.08	$1.95	$1.83	$1.74	$1.63
Book value—end of year	$23.83	$22.82	$22.12	$21.31	$20.53
Market price—high-low	22½-15⅞	19¼-14⅛	20⅝-16¼	22 -18⅛	23½-19⅞
—end of year	20⅝	18⅛	17¼	19⅜	22
TOTAL ASSETS	$6,531,044	$6,328,174	$5,615,372	$4,984,621	$4,610,706
LONG-TERM DEBT	$2,545,694	$2,594,008	$2,300,488	$1,974,209	$1,948,081
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS	$ 308,674	$ 316,559	$ 268,500	$ 220,000	$ 170,000

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Needs and Resources

Since January 1, 1977, additions to property of $4.0 billion (including nuclear fuel) and retirements of $800 million have resulted in a net increase in gross plant of $3.2 billion. In 1981 the net increase in gross plant of $300 million was due to property additions of $800 million and retirements of $500 million. The amount of retirements was unusually large primarily due to the sale, in February 1981, of a portion of the Catawba Nuclear Station. Projected construction and nuclear fuel costs for the period 1982 through 1984 are $2.02 billion and $514 million, respectively. Included in the projected construction costs are nominal amounts related to the Bad Creek Hydroelectric Station. This pumped storage facility will have a net capability of 1,000,000 KW consisting of four 250,000 KW units, although construction completion has not been definitely scheduled.

On February 24, 1981, the Board of Directors, because of the uncertainty of the availability of funds on reasonable terms, indefinitely delayed completion of Cherokee Unit 1 and interrupted work on Unit 2. This status remains unchanged.

The Board of Directors at its February 1982 meeting approved the withdrawal of the Company's application for a construction permit for the proposed Perkins Nuclear Station. The Company intends to request permission in each of its regulatory jurisdictions to recover costs related to such proposed facility. The Company has incurred no material costs and has no commitments the cancellation of which would result in any material costs with respect to such facility.

The construction program currently requires expenditures greater than cash generated internally from operations. The Company initially funds the excess with short-term bank borrowings and commercial paper. While the Company prefers to limit short-term debt to about $150 million, it presently has bank lines of credit of $305 million. Since 1977 the Company has refunded all of its short-term debt at least once each year. In early 1982 approximately $190 million will be obtained from long-term financings to reduce short-term debt, which was $171 million as of December 31, 1981.

During the past five years, financings have included $1.0 billion in long-term debt (principally first and refunding mortgage bonds), $290 million in preferred stock and $530 million in common stock. Since November 1978 sales of interests in the Catawba Nuclear Station have provided $781 million.

In February 1981 the Company sold a 75 percent interest in Unit 1 of the Catawba Nuclear Station (Catawba) and 37.5 percent of the station's support facilities to groups of the Company's North Carolina and South Carolina rural electric cooperative customers. Cash proceeds of $521 million were received from the sale. The Catawba sale, coupled with funds from operations, enabled the Company to generate 94 percent of its capital requirements internally, precluding the need for long-term financing in 1981.

An agreement to sell 25 percent of Unit 2 of Catawba to a group of South Carolina municipalities was reached in August 1981. The sale may be consummated by mid-1982. It would provide cash proceeds of approximately $250 million.

To further minimize capital expenditures, the Company has initiated a comprehensive load management program. The program is designed to limit future construction costs by encouraging consumers to reduce demands on the system without restricting the continued economic development of the Company's service area.

The Company is committed to improving its financial strength to provide increased financing flexibility. The Company believes that in the current economic environment, it is important to seek a stronger capital structure and to maintain manageable levels of long-term debt.

At year-end the Company attained a level of capitalization of 48 percent long-term debt, 13 percent preferred stocks and 39 percent common equity. On January 7, 1982 the Company issued 3,727,544 shares of common stock with a market value of $73,489,000 in exchange for portions of several series of first and refunding mortgage bonds having a face value of $119,902,000. A non-taxable gain of $48,304,000 on the retirement of bonds was recorded in 1982 as an extraordinary item. This enabled the Company to increase

its common equity ratio from 39.4 percent at December 31, 1981 to 41.7 percent. The Company plans to continue to evaluate opportunities to increase its financial strength without diluting existing shareholders' equity.

From 1977 to 1981, funds from operations provided 29 percent of capital requirements, not including cash generated from the two Catawba sales. It is the Company's long-range objective to generate at least 50 percent of its capital requirements from internal sources. The inclusion of construction work in progress and completed generating units in rate base and a higher rate of return on investment will aid in increasing the level of internal cash generation. These matters were considered in recent rate applications in the Company's three rate jurisdictions. In December 1981 the North Carolina Utilities Commission issued a rate order allowing a 16.5 percent return on common equity, inclusion in rate base of McGuire Unit 1, which was placed in commercial operation on December 1, 1981, as well as certain construction work in progress. In January 1982 The Public Service Commission of South Carolina issued a rate order allowing a 13.0 percent return on common equity and the inclusion in rate base of McGuire Unit 1. The June 1981 wholesale request is under consideration by the Federal Energy Regulatory Commission. Since inflation has continued to increase costs in 1981, the Company expects to file further requests for increased rates in 1982.

Fixed charge coverage, using the Securities and Exchange Commission (SEC) method, has not changed significantly because of the increasingly high level of embedded costs. During 1981 this coverage increased to 2.73 times, compared with 2.71 times in 1977; this indicator continues to remain below the Company's goal of 3.5 times.

Results of Operations

Net Income and Dividends

From 1977 to 1981, earnings per share (EPS) increased 32 percent from $2.41 to $3.19. The earned return on common equity increased from 12.0 percent in 1977 to 13.7 percent in 1981. Dividends per share increased 28 percent from $1.63 in 1977 to $2.08 for 1981.

Revenues

Revenues increased by 51 percent over the 1977-81 period. Increases in rates charged to customers and in kilowatt-hour sales were the major contributors to the higher revenues. The rate increases were necessitated by the effects of inflation, the inclusion of construction work in progress in rate base and the need for a higher return on investment. Primarily because of growth in the number of customers, total kilowatt-hour sales increased from 48.8 billion in 1977 to 53.5 billion in 1981, an increase of 10 percent.

Operating Expenses

Increases in total electric expenses have substantially offset the increase in revenues during the 1977-81 period. The most significant increase is in operating and maintenance expense, which rose 74 percent. Inflation (see "Supplemental Financial Data — Effects of Changing Prices"), increased generation from fossil-fired stations, decreased hydroelectric generation and increased requirements by the Nuclear Regulatory Commission were the key factors.

Other

Over the five-year period allowance for funds used during construction (included in both other income and interest deductions) increased, primarily as a result of higher construction work in progress and higher embedded cost of funds. Interest income increased $19 million from 1980 to 1981, largely through the investment of proceeds from the Catawba sale. Earnings of subsidiaries amounted to $15 million in 1981. The Company actively seeks to improve the rate of return on investment in its subsidiaries, the earnings of which are reflected in other income. Interest deductions and dividends on preferred and preference stocks have increased since 1977 because of higher interest rates during the subsequent period and the need for additional capital.

Item 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company were prepared by management which is responsible for their integrity and objectivity. The statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions that should be included and the other information in the annual report is consistent with those statements. In preparing the financial statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. The Company's accounting controls provide reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected by employees within a timely period in the normal course of performing their assigned functions. The Company's accounting controls are continually reviewed for effectiveness and are augmented by written policies, standards and procedures, and a strong program of internal audit.

The board of directors pursues its oversight role for the financial statements through the audit committee, composed solely of directors who are not officers or employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each and to monitor the discharge by each of their responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte Haskins & Sells, who have free access to the audit committee or the board, without management present, to discuss internal accounting control, auditing and financial reporting matters.

AUDITORS' OPINION

DUKE POWER COMPANY:

We have examined the financial statements and supplemental schedules of Duke Power Company listed in the accompanying index on page 22. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying balance sheets and statements of capitalization, income, retained earnings, and source of funds for plant construction costs present fairly the financial position of the Company at December 31, 1981 and 1980 and the results of its operations and the source of its funds for plant construction costs for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles applied on a consistent basis. Also, in our opinion, the supplemental schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

Deloitte Haskins & Sells
DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 15, 1982

DUKE POWER COMPANY

STATEMENTS OF INCOME

	Year Ended December 31		
	1981	1980	1979
		(Dollars in thousands)	
ELECTRIC REVENUES (Notes 1 and 2)	$1,908,454	$1,682,822	$1,492,557
ELECTRIC EXPENSES			
Operation			
Fuel used in electric generation	790,967	680,693	589,402
Net interchange and purchased power (credit)	25,068	(12,908)	(17,254)
Wages, benefits and materials	264,488	211,014	180,338
Maintenance of plant facilities	131,670	114,597	94,598
Depreciation and amortization (Note 1)	142,899	131,441	125,437
General taxes	139,140	124,422	112,655
Income taxes (Notes 1 and 7)	137,872	153,463	153,504
Total electric expenses	1,632,104	1,402,722	1,238,680
Electric operating income	276,350	280,100	253,877
OTHER INCOME (Notes 1, 7 and 10)			
Allowance for equity funds used during construction	159,285	150,846	121,701
Earnings of subsidiaries, net	14,662	3,418	10,447
Other, net (deduction)	28,791	(3,299)	(20,314)
Income taxes—other, net (deduction)	(9,442)	(982)	16,320
Income taxes—credit	60,747	58,382	40,458
Total other income	254,043	208,365	168,612
Income before interest deductions	530,393	488,465	422,489
INTEREST DEDUCTIONS			
Interest on long-term debt	245,070	220,271	179,363
Other interest	11,694	17,287	9,752
Allowance for borrowed funds used during construction (credit) (Note 1)	(62,622)	(60,184)	(41,386)
Total interest deductions	194,142	177,374	147,729
NET INCOME	336,251	311,091	274,760
Dividends on preferred and preference stocks	57,895	58,612	52,562
EARNINGS FOR COMMON STOCK	$ 278,356	$ 252,479	$ 222,198
COMMON STOCK DATA			
Average shares outstanding (thousands)	87,313	81,985	77,168
Earnings per share	$3.19	$3.08	$2.88
Dividends per share	$2.08	$1.95	$1.83

See notes to financial statements.

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DUKE POWER COMPANY

STATEMENTS OF SOURCE OF FUNDS FOR
PLANT CONSTRUCTION COSTS

	Year Ended December 31		
	1981	1980	1979
	(Dollars in thousands)		
FUNDS FROM OPERATIONS			
Net income	$336,251	$311,091	$274,760
Non-fund items			
Depreciation and nuclear fuel amortization	224,675	210,600	190,110
Deferred income taxes and investment tax credit, net of amortization	109,572	68,198	91,991
Equity component of the allowance for funds used during construction	(159,285)	(150,846)	(121,701)
Other, net	(13,146)	2,989	(5,854)
Funds from operations	498,067	442,032	429,306
Dividends paid	(239,598)	(217,618)	(193,585)
Funds retained in the business	258,469	224,414	235,721
FUNDS FROM FINANCING AND SALE OF ASSETS—NET PROCEEDS			
Sale of an interest in the Catawba Nuclear Station (Note 10)	520,562	—	—
Nuclear fuel trusts	42,248	30,664	76,254
Common stock	35,954	105,829	131,561
First mortgage bonds	—	271,150	295,768
Preferred stock	—	49,323	49,251
Term note	—	10,000	—
Increase (decrease) in notes payable for construction	(25,650)	85,000	112,000
Funds from financing and sale of assets	573,114	551,966	664,834
Total available funds	831,583	776,380	900,555
INCREASE IN WORKING CAPITAL REQUIREMENT	(92,946)	(31,000)	(43,536)
RETIREMENTS OF LONG-TERM DEBT AND PREFERRED STOCK	(93,551)	(43,211)	(150,412)
PLANT CONSTRUCTION EXPENDITURES	645,086	702,169	706,607
Equity component of the allowance for funds used during construction	159,285	150,846	121,701
PLANT CONSTRUCTION COSTS	$804,371	$853,015	$828,308
SUMMARY OF PLANT CONSTRUCTION COSTS			
Production	$504,292	$590,420	$571,023
Transmission	36,233	51,300	42,566
Distribution	112,073	92,990	89,841
General	22,557	25,000	26,812
Subtotal	675,155	759,710	730,242
Nuclear fuel	129,216	93,305	98,066
PLANT CONSTRUCTION COSTS	$804,371	$853,015	$828,308

See notes to financial statements.

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DUKE POWER COMPANY

BALANCE SHEETS

ASSETS

	December 31	
	1981	1980
	(Dollars in thousands)	
ELECTRIC PLANT		
(At original cost—Notes 1, 6 and 11)		
Electric plant in service	$5,662,674	$4,419,152
Less accumulated depreciation and amortization	1,842,831	1,629,109
Electric plant in service, net	3,819,843	2,790,043
Construction work in progress	2,178,464	3,114,807
Total electric plant, net	5,998,307	5,904,850
OTHER PROPERTY AND INVESTMENTS		
Other property—at cost (less accumulated depreciation: 1981—$6,781; 1980—$4,551)	26,444	22,447
Investments in and advances to subsidiaries (Note 1)	54,981	34,373
Other investments—at cost or less (Note 10)	22,592	8,845
Total other property and investments	104,017	65,665
CURRENT ASSETS		
Cash (Note 9)	4,526	1,835
Receivables (less allowance for losses: 1981—$3,998; 1980—$4,064)	189,036	128,549
Materials and supplies—at average cost		
Coal	126,581	133,156
Other	93,457	79,552
Prepayments	6,172	5,334
Total current assets	419,772	348,426
DEFERRED DEBITS		
Debt expense, being amortized over terms of related debt	3,113	3,282
Other	5,835	5,951
Total deferred debits	8,948	9,233
TOTAL ASSETS	$6,531,044	$6,328,174

See notes to financial statements.

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DUKE POWER COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31	
	1981	1980
	(Dollars in thousands)	
CAPITALIZATION		
(See Statements of Capitalization)		
Common stock equity	$2,108,935	$1,969,140
Preferred and preference stocks without sinking fund requirements	388,610	395,858
Preferred stocks with sinking fund requirements	308,674	316,559
Long-term debt	2,545,694	2,594,008
Total capitalization	5,351,913	5,275,565
CURRENT LIABILITIES		
Accounts payable	87,290	61,127
Interest accrued	71,615	71,056
Taxes accrued	59,958	45,610
Other	26,872	24,282
Total	245,735	202,075
Notes payable for construction—pending permanent financing (Note 9)	171,350	197,000
Current maturities of long-term debt and preferred stock	79,646	74,110
Total current liabilities	496,731	473,185
ACCUMULATED DEFERRED INCOME TAXES (Notes 1 and 7)	419,958	374,684
DEFERRED CREDITS		
Investment tax credit (Notes 1 and 7)	249,208	193,276
Other	13,234	11,464
Total deferred credits	262,442	204,740
COMMITMENTS AND CONTINGENCIES (Note 11)		
TOTAL CAPITALIZATION AND LIABILITIES	$6,531,044	$6,328,174

See notes to financial statements.

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DUKE POWER COMPANY

STATEMENTS OF CAPITALIZATION AND RETAINED EARNINGS

CAPITALIZATION

	December 31	
	1981	1980
	(Dollars in thousands)	
COMMON STOCK EQUITY (Note 3)		
Common stock, no par, 150,000,000 and 100,000,000 shares authorized and 88,482,596 and 86,294,416 shares outstanding for 1981 and 1980, respectively	$1,579,093	$1,535,895
Retained earnings	529,842	433,245
Total common stock equity	2,108,935	1,969,140
PREFERRED AND PREFERENCE STOCKS WITHOUT SINKING FUND REQUIREMENTS (Note 4)		
Preferred stock	375,000	375,000
Preference stock	13,610	20,858
Total preferred and preference stocks without sinking fund requirements	388,610	395,858
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS (Note 5)	308,674	316,559
LONG-TERM DEBT (Note 6)		
First and refunding mortgage bonds	2,376,250	2,418,000
Sinking fund debentures, 4⅞% – due 1982	25,000	25,000
Term note, 9.025% – due 1985	8,500	10,000
Pollution control obligations, 75% of prime rate - due 1983	2,500	2,500
Capitalized leases	101,579	103,862
Nuclear fuel trusts	125,000	125,000
Unamortized debt discount and premium, net	(15,489)	(16,244)
Current maturities of long-term debt	(77,646)	(74,110)
Total long-term debt	2,545,694	2,594,008
TOTAL CAPITALIZATION	$5,351,913	$5,275,565

RETAINED EARNINGS

	Year Ended December 31		
	1981	1980	1979
		(Dollars in thousands)	
BALANCE—Beginning of year	$433,245	$343,225	$266,173
ADD—Net income	336,251	311,091	274,760
Total	769,496	654,316	540,933
DEDUCT			
Dividends			
Common stock	181,703	159,240	141,035
Preferred and preference stocks	57,895	58,612	52,562
Capital stock expense	56	3,219	4,111
Total deductions	239,654	221,071	197,708
BALANCE—End of year	$529,842	$433,245	$343,225

See notes to financial statements.

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DUKE POWER COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

A. *Additions to Electric Plant.* The Company capitalizes all construction-related direct labor and materials, as well as indirect construction costs, including general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized; the cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

B. *Allowance for Funds Used During Construction (ADC).* ADC is an accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are capitalized in the same manner as construction labor and material costs. ADC, a non-cash, non-operating item, is recognized as a cost of "Electric Plant" with offsetting credits to "Other Income" and "Interest Deductions" because, under established regulatory rate practices, a utility is permitted to include a fair return on, and the recovery of, these capital costs through their inclusion in rate base and in the provision for depreciation.

ADC, which is compounded semi-annually, was calculated on average embedded rates (net of applicable income taxes) of 8.67 percent, 8.10 percent and 8.01 percent for 1981, 1980 and 1979, respectively.

North Carolina statutes require that capital expenditures for construction work in progress (CWIP), incurred on or after July 1, 1979 and requested in rate applications after such date, be included in rate base for ratemaking purposes. Under such statutes, utilities are permitted to continue capitalizing ADC with respect to CWIP not included in rate base but are not permitted to do so with respect to CWIP included in rate base. At December 31, 1981, $144,841,000 of CWIP was included in North Carolina rate base and therefore excluded for purposes of capitalizing ADC.

C. *Depreciation and Amortization.* Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted average depreciation rates were 3.44 percent for 1981 and 3.33 percent for 1980 and 1979. All coal-fired generating units are depreciated at the rate of 3.57 percent. Beginning October 1979, the depreciation rate on nuclear plant was revised from 3.57 percent to 4.00 percent. This rate includes an allowance for decommissioning costs. However, the Company is continuing to evaluate the impact of such costs. Provisions for amortization of nuclear fuel, which are included in "Fuel used in electric generation," are recorded using the unit of production method. Because of the present unavailability of reprocessing facilities, nuclear fuel amortization includes an estimate of disposal costs.

D. *Subsidiaries.* The Company has five wholly-owned operating subsidiaries. Mill-Power Supply Company is a wholesale jobber and distributor of electrical supplies and equipment and acts as purchasing agent for the Company. Crescent Land & Timber Corp. is a land management and forestry company, whose principal holdings are non-utility land acquired from the Company. Eastover Mining Company mines coal for the Company (supplying 12 percent of its requirements for 1981) on properties owned or leased by Eastover Land Company, the Company's mineral holding subsidiary. Western Fuel, Inc. is involved in the exploration and development of uranium ore deposits in central Wyoming.

The Company follows the equity method of accounting for such subsidiaries. Retained earnings include $41,234,000 of undistributed earnings of subsidiaries at December 31, 1981. Dividends received from subsidiaries were $981,302 in 1981, $1,675,000 in 1980 and $5,800,000 in 1979.

E. *Income Taxes.* The Company and its subsidiaries file a consolidated federal income tax return. Income taxes are allocated to each company based on its taxable income or loss.

Income taxes are allocated to electric operating expense and to non-electric operations under "Other Income." The "Income taxes—credit" classified under "Other Income" results from tax deductions of interest costs relating to investments in non-utility properties, mainly CWIP not included in rate base.

Deferred income taxes are provided for timing differences between book and tax income, principally resulting from accelerated tax depreciation, capitalized taxes and employee benefits, cost of removal, and nuclear fuel disposal costs.

Investment tax credit is deferred and amortized over the useful lives of the related properties. At December 31, 1981, the Company had unused investment tax credit approximating $60 million, which will be available for use through 1996.

F. *Fuel Cost Adjustment Procedures.* The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel costs. Procedures for North and South Carolina retail jurisdictions provide for periodic reviews of fuel costs with provisions for changing such costs in base rates. With respect to South Carolina, the Company continues to reflect in revenues the difference between actual fuel costs incurred and fuel costs recovered through base rates. Procedures for the wholesale jurisdiction provide for monthly fuel cost adjustments.

2. Rate Matters

General rate increases since January 1, 1979 are as follows (dollars in thousands):

Jurisdiction and Date Implemented	Percent Increase	Annualized on 1981 Sales	Approximate Revenue Recorded 1981	1980	1979
N. C. Retail					
October 8, 1979	3.20	$ 32,900	$ 32,900	$30,900	$ 6,800
October 3, 1980	6.03	66,700	66,700	14,800	—
December 1, 1981	14.99(a)	169,900	13,400	—	—
S. C. Retail					
October 8, 1979	6.02	24,500	24,500	25,200	4,900
December 1, 1981	13.00(b)	55,400	21,600	—	—
Wholesale					
October 8, 1979	3.45	5,700	5,700	6,500	1,400
October 3, 1980	6.71	13,700	13,700	3,300	—
January 23, 1981	2.10	4,600	4,100	—	—
December 1, 1981	18.04(a)	41,500	2,700(c)	—	—
		$414,900	$185,300	$80,700	$13,100

(a) These increases were implemented in two stages, on October 18 and on December 1, the last of which was to reflect the commercial operation of McGuire Unit 1.

(b) This increase was implemented in three stages, on January 28, October 18, and December 1; the last of which was to reflect the commercial operation of McGuire Unit 1.

(c) Subject to refund with interest.

3. Common Stock and Retained Earnings

Common Stock

In 1981, 1980 and 1979, the Company received $35,954,000, $108,361,000 and $134,924,000 from the issuance of 1,884,944 shares, 6,278,820 shares and 6,999,292 shares of common stock, respectively (see Note 12).

At December 31, 1981, certain shares of common stock were reserved for issuance as follows:

	Shares
Stock Purchase-Savings Program for Employees	5,254,078
Conversion of Preference Stock	581,627
Dividend Reinvestment and Stock Purchase Plan	510,066
Employees' Stock Ownership Plan	2,901,998
Total	9,247,769

Retained Earnings

None of the Company's retained earnings as of December 31, 1981 were restricted with respect to the declaration or payment of dividends.

4. Preferred and Preference Stocks Without Sinking Fund Requirements

At December 31, 1981 and 1980, 10,000,000 shares of preferred stock ($100 par value) were authorized and issuable with or without sinking fund requirements. In addition, 1,500,000 shares of preference stock ($100 par value) were authorized at December 31, 1981 and 1980.

The outstanding Preference Stock, 6¾ percent Convertible Series AA, is convertible into shares of common stock at the adjusted conversion price of $23.89 per share, each share of preference stock being valued at $100 par for such purpose. The conversion price is subject to certain adjustments designed to protect the conversion privilege against dilution. In 1981, 1980 and 1979, 72,477 shares, 127,476 shares and 88,405 shares were converted into 303,236 shares, 526,657 shares and 357,418 shares of common stock, respectively.

Preferred and preference stocks without sinking fund requirements at December 31, 1981 and 1980 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1981	1980
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
8.70% F	1970	600,000	60,000	60,000
8.20% G	1971	600,000	60,000	60,000
7.80% H	1972	600,000	60,000	60,000
8.28% K	1977	500,000	50,000	50,000
8.84% M	1978	400,000	40,000	40,000
6¾%, AA Convertible	1969	136,109	13,610	—
		208,586	—	20,858
Total			$388,610	$395,858

5. Preferred Stocks With Sinking Fund Requirements

At December 31, 1981 and 1980, 10,000,000 shares of preferred stock ($100 par value) were authorized and issuable with or without sinking fund requirements. In addition, 10,000,000 shares of preferred stock A ($25 par value) were authorized at December 31, 1981 and 1980.

Preferred stocks with sinking fund requirements at December 31, 1981 and 1980 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1981	1980
7.35 % I	1973	600,000	$ 60,000	$ 60,000
8.20 % J	1977	500,000	50,000	50,000
8.375% L	1978	500,000	50,000	50,000
8.84 % N	1979	500,000	50,000	50,000
11.00 % O	1980	500,000	50,000	50,000
10.76 % A	1975	2,280,000	57,000	—
		2,340,000	—	58,500
		Shares Reacquired		
Less: Preferred shares reacquired for current and future sinking fund requirements—at cost				
10.76% A		119,998	(2,660)	—
		83,000	—	(1,941)
8.84% N		32,500	(2,430)	—
11.00% O		13,750	(1,236)	—
Current sinking fund requirement				
8.20% J			(2,000)	—
Total			$308,674	$316,559

The annual sinking fund requirements through 1986, net of amounts previously acquired, are $2,000,000 in 1982, $4,000,050 in 1983, $7,900,000 in 1984, $7,900,000 in 1985 and $9,525,000 in 1986, with some additional redemptions permitted at the Company's option.

The call provisions for the outstanding preferred and preference stocks specify various redemption prices not exceeding 111 percent of par values plus accumulated dividends to the redemption date.

6. Long-Term Debt

First and refunding mortgage bonds outstanding at December 31, 1981 and 1980 were as follows (see Note 12) (dollars in thousands):

Series	Year Due	1981	1980	Series (continued)	Year Due	1981	1980
3¼ %	1981	$ —	$ 35,000	7⅜%B	2001	$ 40,000	$ 40,000
3⅝%	1986	30,000	30,000	7¾ %	2002	100,000	100,000
14⅜%	1987	50,000	50,000	7⅞%B	2002	75,000	75,000
12%	1990	75,000	75,000	7¾ %	2003	100,000	100,000
4½ %	1992	50,000	50,000	8⅛%B	2003	100,000	100,000
4¼ %B	1992	50,000	50,000	9¾ %	2004	100,000	100,000
11%	1994	91,250	98,000	9½ %	2005	100,000	100,000
4½ %	1995	40,000	40,000	8⅜ %	2006	100,000	100,000
5⅜ %	1997	75,000	75,000	8⅛ %	2007	125,000	125,000
6⅜ %	1998	75,000	75,000	9⅜ %	2008	125,000	125,000
7%	1999	75,000	75,000	10⅛ %	2009	150,000	150,000
8%B	1999	75,000	75,000	10⅛%B	2009	150,000	150,000
8½ %	2000	75,000	75,000	14⅞ %	2010	100,000	100,000
8⅝%B	2000	100,000	100,000	13⅛%B	2010	50,000	50,000
7½ %	2001	100,000	100,000	Total		$2,376,250	$2,418,000

Substantially all electric plant was mortgaged at December 31, 1981.

The annual maturities of long-term debt (including sinking fund requirements and capitalized lease principal payments) through 1986 are $77,646,000 in 1982, $62,510,000 in 1983, $49,353,000 in 1984, $12,085,000 in 1985 and $40,392,000 in 1986.

Included in the annual maturities are amounts relating to $125,000,000 in outstanding obligations under two nuclear fuel trusts. Such maturities are based on estimated nuclear fuel consumption. The Company intends to transfer title to additional nuclear fuel to the trusts to replace such amounts as fuel is consumed.

7. Income Tax Expense

Income tax expense consisted of the following (dollars in thousands):

	Year Ended December 31		
	1981	1980	1979
Electric Expenses			
Current income taxes			
Federal	$ 30,244(a)	$ 69,134	$ 61,698
State	11,183	16,121	14,580
	41,427	85,255	76,278
Deferred taxes, net			
Excess tax over book depreciation	49,353(b)	25,114	27,594
Capitalized taxes, employee benefits, etc.	16,672	17,680	16,545
Revenues refundable	(8,281)	—	—
Repair allowance and cost of removal	(38)(b)	5,872	7,369
Nuclear fuel disposal costs	(12,336)	(12,263)	(10,800)
	45,370	36,403	40,708
Investment tax credit			
Deferred	56,146	36,854	41,196
Amortization of deferments (credit)	(5,071)	(5,049)	(4,678)
	51,075	31,805	36,518
Total electric expenses	137,872	153,463	153,504
Other Income			
Income taxes—other, net (deduction)	51,592(c)	982	(16,320)
Income taxes—credit	(60,747)	(58,382)	(40,458)
Total other income	(9,155)	(57,400)	(56,778)
Total income tax expense	$128,717	$ 96,063	$ 96,726

Total current income taxes were $24,002,000, $30,037,000 and $19,500,000, of which state income taxes were $11,086,000, $10,753,000 and $8,917,000, for 1981, 1980 and 1979, respectively.

Total deferred income taxes were $53,641,000, $34,221,000 and $40,708,000, of which deferred state income taxes were $7,899,000, $3,896,000 and $4,399,000, for 1981, 1980 and 1979, respectively.

(a) Electric federal income tax reflects substantial investment tax credit utilization related to the tax gain on sale of assets in February 1981.

(b) Reflects changes attributable to the Economic Recovery Tax Act of 1981. Deferred taxes on depreciation also reflect Unit 1 of McGuire Nuclear Station coming in service December 1, 1981.

(c) Includes $42,150,000 resulting from the sale of assets in February 1981 and nominal amounts thereafter (see Note 10). Such income taxes, which are included in "Other, net (deduction)" on the Statements of Income, reflect a taxable gain in excess of book gain resulting principally from the treatment of ADC.

Income taxes differ from amounts computed by applying the statutory tax rate to pretax income as follows (dollars in thousands):

	Year Ended December 31		
	1981	1980	1979
Income taxes on pretax income at the statutory federal rate of 46%	$213,885	$187,291	$170,884
Increase (reduction) in tax resulting from:			
Allowance for all funds used during construction (ADC)	(102,077)	(97,074)	(75,020)
Amortization of electric investment tax credit deferrals	(5,071)	(5,049)	(4,688)
State income taxes, net of federal income tax benefits	13,595	9,044	7,483
Increase in tax expense primarily due to excess of tax gain over book profit on sale of assets	12,468	—	—
Other items, net	(4,083)	1,851	(1,933)
Total income tax expense (see above)	$128,717	$ 96,063	$ 96,726

8. Retirement Plan

The Company and two of its subsidiaries have a non-contributory, defined benefit retirement plan covering substantially all their employees. The Company's policy is to fund pension costs accrued. Total pension expense amounted to $31,896,000 in 1981, $26,782,000 in 1980 and $23,844,000 in 1979. Effective September 1, 1980 the plan was amended to provide for certain plan changes including increased benefits for active and retired employees. Also, in 1981, the actuarial cost method and certain actuarial assumptions were changed. The effect of these changes did not significantly increase the Company's pension cost for 1981.

A comparison of accumulated plan benefits and plan net assets at December 31, 1980, the date of the latest actuarial report, and December 31, 1979 is as follows (dollars in thousands):

	1980	1979
Actuarial present value of accumulated plan benefits		
Vested	$202,851	$126,757
Non-Vested	60,332	13,090
Total	$263,183	$139,847
Net assets available for benefits	$244,008	$176,840

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 8.3% in 1980 and 7.5% in 1979.

9. Short-Term Borrowings

The Company has lines of credit with 77 commercial banks and uses these lines, plus the sale of commercial paper, to finance its current cash requirements.

At December 31, 1981, the lines of credit were on either a fee basis and/or a compensating balance basis, with average annual balance requirements of $1,748,000. Bank loans, normally for 90 days or less, are principally at the lending bank's commercial prime interest rate. Certain of the Company's bank line arrangements may require additional balances or fees related to annual average borrowings.

A summary of short-term borrowings and credit arrangements is as follows (dollars in thousands):

	1981	1980	1979
Amount outstanding at year-end—average rates of 11.69%, 17.74% and 14.09%, respectively	$171,350	$197,000	$112,000
Maximum amount outstanding during the year	$250,398	$197,000	$125,400
Average amount outstanding during the year	$ 38,829	$ 84,466	$ 33,894
Weighted average interest rate for the year—computed on a daily basis	15.39%	12.91%	11.93%
Lines of credit at year-end	$305,400	$280,400	$280,000

10. Other Income

In February 1981, the Company sold a 75 percent interest in Unit 1 of the Catawba Nuclear Station (Catawba) and 37.5 percent of the station's support facilities to groups of North Carolina and South Carolina rural electric cooperative customers. At closing, $521 million and two notes totaling $76 million were received. The notes are non-interest bearing until 10 years after the first Catawba unit begins commercial operation, after which, interest and principal payments commence. The Company has discounted the notes and recorded the present value ($13.8 million at December 31, 1981) under "Other investments." The implicit interest on the notes is accrued monthly. The net of tax profit from the sale was $4 million. At December 31, 1981, "Construction work in progress" included $401,502,000 representing the Company's investment in its remaining interest in Catawba.

In 1979, the Company made a provision to write down the carrying value of an investment made pursuant to the terms of a certain coal supply contract. A charge was recorded of approximately $13,564,000 (after giving effect to income taxes of $12,264,000).

11. Commitments and Contingencies

A. Construction Program

The Company is engaged in a long-range construction program for which substantial commitments have been made. Projected construction and nuclear fuel costs for the years 1982 through 1984 are $2.02 billion and $514 million, respectively. The program is subject to periodic review and revision, and actual construction costs incurred may vary from such estimates. This is due to various factors including changing levels of inflation, revised load estimates, the cost and availability of capital, and the outcome of licensing and environmental matters.

On February 24, 1981, the Board of Directors, because of the uncertainty of the availability of funds on reasonable terms, indefinitely delayed completion of Cherokee Unit 1 and interrupted work on Unit 2. This status remains unchanged.

The management of the Company intends to recommend to the Board of Directors at its February meeting the withdrawal of the Company's application for a construction permit for the proposed Perkins Nuclear Station. If such recommendation is approved, the Company intends to request permission in each of its regulatory jurisdictions to recover costs related to such proposed facility. The Company has incurred no material costs and has no commitments the cancellation of which would result in any material costs with respect to such facility.

B. Nuclear Insurance

The Company's public liability for claims resulting from any nuclear incident is limited to $560 million under provisions of the Price-Anderson Act which provides for nuclear liability insurance up to that amount. A portion of this insurance is provided through Nuclear Regulatory Commission regulations pursuant to which the Company could be assessed up to $5 million for each of its licensed reactors in the event there is a nuclear incident involving any licensed facility in the nation with a maximum of $10 million a year for each of its

licensed reactors in the event of more than one incident. At December 31, 1981, the Company had four licensed reactors.

Property damage coverage for certain of the Company's nuclear facilities is provided through membership in Nuclear Mutual Limited (NML). If NML's losses were to exceed its reserves, the Company could be liable, on a pro rata basis, for additional assessments of up to $72 million, representing 14 times the Company's current annual premium to NML.

The Company is a member of Nuclear Electric Insurance Limited (NEIL) which provides insurance for the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. If losses were to exceed the accumulated funds available to NEIL, the Company would be liable for a retrospective premium adjustment of up to five times the regular annual premium. Maximum potential liability per incident currently is estimated to be $26 million.

The Company anticipates purchasing from NEIL, through its Excess Property Insurance Program, $500 million of property damage insurance. This is in addition to the $450 million of coverage provided by the Company's underlying property damage policies issued through the commercial market. If losses were to exceed the accumulated funds available to NEIL for the Excess Property Insurance Program, the Company would be liable for a retrospective premium adjustment of up to 7.5 times the regular annual premium in the policy year in which the loss is incurred.

C. Leases

Minimum lease commitments as of December 31, 1981 under all capital and operating leases are not material.

12. Subsequent Events

On January 7, 1982, the Company issued 3,727,544 shares of common stock with a market value of $73,489,000 in exchange for portions of several series of outstanding first and refunding mortgage bonds with a face value of $119,902,000. A non-taxable gain of $48,304,000 on the retirement of the bonds was recorded in 1982 as an extraordinary item.

SUPPLEMENTAL FINANCIAL DATA—(Unaudited)

Quarterly Financial Data

A summary of quarterly financial data for 1981 and 1980 is as follows (dollars in thousands except per share data):

	Electric Revenues	Electric Operating Income	Net Income	Earnings Per Common Share
1981 by Quarter*				
Fourth	$484,782	$64,388	$79,626	$0.74
Third	499,216	64,188	83,740	0.79
Second	426,200	70,397	80,111	0.76
First	498,256	77,377	92,774	0.90
1980 by Quarter*				
Fourth	$425,219	$76,760	$76,764	$0.72
Third	450,861	66,433	77,877	0.77
Second	367,987	57,658	68,987	0.67
First	438,755	79,249	87,463	0.92

* Quarterly earnings generally fluctuate with seasonal weather conditions, timing of rate increases (including fuel cost adjustment procedures) and maintenance of electric generating units, especially nuclear-fueled units.

Effects of Changing Prices

In recent years, the impact of general inflation and changes in specific prices has caused distortions in traditional accounting measurements of income and capital. In response to this problem, the Financial Accounting Standards Board (FASB) issued Statement No. 33 requiring disclosure of the effects of inflation on a company's operations and financial position.

Because the accompanying supplementary information involves various assumptions and approximations, it should be viewed as an estimate of the effects of inflation, rather than a precise measurement.

Constant Dollar Accounting

Constant dollar accounting reflects the overall decline in the purchasing power of the dollar by restating historical costs in terms of dollars of equal purchasing power.

Constant dollar amounts for electric plant in service were determined by indexing surviving historical costs of plant with the Consumer Price Index for all Urban Consumers (CPI-U). Historical depreciation rates were applied to the restated amounts of plant thereby trending the provision for depreciation to reflect the impact of general inflation.

Current Cost Accounting

Current cost accounting reflects changes in specific prices of the property used in the Company's operations from the date the property was acquired to the present. This method differs from constant dollar accounting to the extent that costs of specific utility property have increased more or less rapidly than the rate of general inflation. The current cost amounts of plant in service represent the estimated cost for replacing existing plant facilities and were determined by indexing surviving plant costs by internally generated indices or the Handy-Whitman Index of Public Utility Construction Costs. Since plant facilities are not expected to be replaced precisely in kind, "current cost" does not necessarily represent the replacement cost of existing productive capacity. Current cost depreciation is computed by applying the same rates used in the historical cost and constant dollar statements to the current cost plant amounts.

Effects of Rate Regulation

Under the Company's present ratemaking procedures, only the historical cost of plant in service is recoverable in rates as depreciation. Therefore, the excess of the cost of plant stated in terms of constant dollars or current costs over the historical cost of plant, resulting from inflation in the current year, is not presently recoverable in rates as depreciation, and is reflected as a reduction to net recoverable cost.

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The reduction is offset by the Company having significant amounts of long-term debt outstanding, as well as other net monetary liabilities, which will be paid back in dollars of less purchasing power. Thus, the gain from decline in purchasing power of net amounts owed in the accompanying schedules results from inflation's effect on obligations to pay cash at a future date.

Other

Income statement items other than depreciation have not been adjusted. The Company's operation and maintenance expenses already include the average effects of changing prices during the period and, therefore, no adjustments have been made to them.

No adjustments to income tax expense have been made in computing the impact of inflation since only historical costs are deductible for income tax purposes.

Supplementary Statement of Earnings for Common Stock Adjusted for Changing Prices

	Year Ended December 31, 1981		
	Historical $	Constant Dollar	Current Cost
		(Dollars in thousands)	
Electric revenues	$1,908,454	$1,908,454	$1,908,454
Operating expenses	1,080,523	1,080,523	1,080,523
Maintenance of plant facilities	131,670	131,670	131,670
Depreciation	142,899	314,177	334,419
Taxes	277,012	277,012	277,012
Total operating expenses	1,632,104	1,803,382	1,823,624
Operating income	276,350	105,072	84,830
Other income	254,043	254,043	254,043
Income before interest	530,393	359,115	338,873
Interest expense	194,142	194,142	194,142
Net income	336,251	164,973	144,731
Dividends on preferred and preference stocks	57,895	57,895	57,895
Earnings for common stock	$ 278,356	$ 107,078*	$ 86,836
Increase in specific prices (current cost) of utility plant held during the year**			$ 784,633
Reduction to net recoverable cost		$ (284,665)	(239,004)
Effect of increase in general price level			(810,052)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			(264,423)
Gain from decline in purchasing power of net amounts owed		326,916	326,916
Net		$ 42,251	$ 62,493

* If the reduction to net recoverable cost of $284,665,000 were reflected, and no recognition were given to the $326,916,000 purchasing power gain, earnings for common stock on a constant dollar basis would have been a loss of $177,587,000.

** At December 31, 1981, current cost of electric plant, net of accumulated depreciation, was $10,055,578,000.

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

	1981	1980	1979	1978	1977
	(In thousands of average 1981 dollars, except per share figures)				
Electric revenues					
In historical dollars	$1,908,454	$1,682,822	$1,492,557	$1,396,720	$1,266,974
In constant dollars	1,908,454	1,857,377	1,870,159	1,947,116	1,901,508
Income from continuing operations					
In historical dollars	336,251	311,091	274,760		
In constant dollars	164,973	185,808	203,721		
In current cost	144,731	167,222	177,978		
Earnings per share for common stock					
In historical dollars	3.19	3.08	2.88		
In constant dollars	1.23	1.48	1.79		
In current cost	.99	1.25	1.45		
Common stock dividends per share					
In historical dollars	2.08	1.95	1.83	1.74	1.63
In constant dollars	2.08	2.15	2.29	2.43	2.45
Market price per common share at year-end					
In historical dollars	20.625	18.125	17.25	19.375	22.00
In constant dollars	19.96	19.11	20.44	26.01	32.20
Net assets at year-end					
In historical dollars	2,108,935	1,969,140	1,758,016		
In constant dollars	2,040,760	2,075,827	2,083,008		
In current cost	2,040,760	2,075,827	2,083,008		
Purchasing power gain on net monetary items	326,916	455,029	484,947		
Decrease in the current cost of electric plant in service, net of inflation, after reduction to net recoverable cost	264,423	494,057	550,817		
Average Consumer Price Index	272.4	246.8	217.4	195.4	181.5

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DUKE POWER COMPANY

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Balance Beginning of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1981					
Electric Plant in Service—At Original Cost					
Production	$1,902,374	$ 927,983(1)	$ 1,058	$ 524	$2,829,823
Transmission	794,988	57,769	1,833	(425)	850,499
Distribution	1,262,939	105,714	11,700	3,630	1,360,583
General	207,821	18,898	5,412	9,125	230,432
Miscellaneous	15,622	1,301	—	—	16,923
Nuclear Fuel	235,408	138,820	—	186	374,414
Total electric plant in service	4,419,152	1,250,485	20,003	13,040(2)	5,662,674
Construction Work in Progress	3,114,807	(450,604)(1)	—	(485,739)(3)	2,178,464
Other Property—At Cost					
Water plant	18,600	5,151	—	(40)	23,711
Transit plant	525	666	—	1,783	2,974
Non-utility plant	7,873	(1,327)	1,077	1,071	6,540
Total other property	26,998	4,490	1,077	2,814(2)	33,225
Total plant	$7,560,957	$ 804,371	$21,080	$(469,885)	$7,874,363
For the Year Ended December 31, 1980					
Electric Plant in Service—At Original Cost					
Production	$1,826,359	$ 14,438	$ 635	$ 62,212	$1,902,374
Transmission	771,644	24,531	1,496	309	794,988
Distribution	1,178,994	90,271	10,993	4,667	1,262,939
General	169,519	19,338	3,842	22,806	207,821
Miscellaneous	10,445	5,177	—	—	15,622
Nuclear fuel	169,552	65,856	—	—	235,408
Total electric plant in service	4,126,513	219,611	16,966	89,994	4,419,152
Construction Work in Progress	2,481,957	632,850	—	—	3,114,807
Other Property—At Cost					
Water plant	18,187	1,494	1,040	(41)	18,600
Transit plant	525	—	—	—	525
Non-utility plant	8,771	(940)	446	488	7,873
Total other property	27,483	554	1,486	447	26,998
Total plant	$6,635,953	$ 853,015	$18,452	$ 90,441(4)	$7,560,957
For the Year Ended December 31, 1979					
Electric Plant in Service—At Original Cost					
Production	$1,829,567	$ 12,441	$15,632	$ (17)	$1,826,359
Transmission	734,580	37,932	1,169	301	771,644
Distribution	1,096,764	89,575	11,043	3,698	1,178,994
General	145,896	27,724	4,954	853	169,519
Miscellaneous	10,201	244	—	—	10,445
Nuclear fuel	147,817	21,735	—	—	169,552
Total electric plant in service	3,964,825	189,651	32,798	4,835	4,126,513
Construction Work in Progress	1,844,323	637,913	—	(279)	2,481,957
Other Property—At Cost					
Water plant	17,473	716	—	(2)	18,187
Transit plant	525	—	—	—	525
Non-utility plant	8,460	28	54	337	8,771
Total other property	26,458	744	54	335	27,483
Total plant	$5,835,606	$ 828,308	$32,852	$ 4,891(5)	$6,635,953

(1) Principally due to Unit 1 of McGuire Nuclear Station commencing commercial operation on December 1, 1981.

(2) Principally due to the purchase of transportation equipment previously leased and other items as explained in note 5.

(3) Represents the book value of an asset (the Catawba Nuclear Station) sold in February 1981.

(4) Principally due to capitalization of leases at December 31, 1980.

(5) Principally due to salvage credit, retirement cost, and adjustments for prior years.

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DUKE POWER COMPANY

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Beginning of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1981						
Accumulated Depreciation of Electric Plant						
Production	$ 699,674	$ 66,907		$ 1,156		$ 765,425
Transmission	233,096	23,037		1,749	$ 66	254,450
Distribution	412,312	44,434		8,000	(66)	448,680
General	64,837	4,921	$ 7,977	3,185	7,118	81,668
Miscellaneous	2,621	—	519	—	—	3,140
	1,412,540	139,299	8,496	14,090	7,118	1,553,363
Accumulated Amortization of Limited Term Plant	75	—	104	—	—	179
Accumulated Amortization of Nuclear Fuel	216,494	—	72,795	—	—	289,289
	1,629,109	139,299	81,395	14,090	7,118	1,842,831
Accumulated Depreciation of Water Plant	4,326	360	—	38	—	4,648
Accumulated Depreciation of Transit Plant	225	125	—	—	1,783	2,133
Total Accumulated Depreciation	$1,633,660	$139,784	$81,395	$14,128	$ 8,901(1)	$1,849,612
For the Year Ended December 31, 1980						
Accumulated Depreciation of Electric Plant						
Production	$ 606,945	$ 61,722		$ 982	$31,989	$ 699,674
Transmission	211,361	22,228		167	(326)	233,096
Distribution	378,134	41,181		7,329	326	412,312
General	55,062	4,268	$ 7,179	2,063	391	64,837
Miscellaneous	2,102	—	519	—	—	2,621
	1,253,604	129,399	7,698	10,541	32,380	1,412,540
Accumulated Amortization of Limited Term Plant	19	—	56	—	—	75
Accumulated Amortization of Nuclear Fuel	145,409	—	71,085	—	—	216,494
	1,399,032	129,399	78,839	10,541	32,380	1,629,109
Accumulated Depreciation of Water Plant	5,027	339	—	1,040	—	4,326
Accumulated Depreciation of Transit Plant	189	36	—	—	—	225
Total Accumulated Depreciation	$1,404,248	$129,774	$78,839	$11,581	$32,380(2)	$1,633,660
For the Year Ended December 31, 1979						
Accumulated Depreciation of Electric Plant						
Production	$ 563,127	$ 59,466		$15,648		$ 606,945
Transmission	190,915	21,314		788	$ (80)	211,361
Distribution	347,125	38,354		7,667	322	378,134
General	48,435	4,297	$ 6,431	4,256	155	55,062
Miscellaneous	1,606	—	496	—	—	2,102
	1,151,208	123,431	6,927	28,359	397	1,253,604
Accumulated Amortization of Limited Term Plant	—	—	19	—	—	19
Accumulated Amortization of Nuclear Fuel	88,042	—	57,367	—	—	145,409
	1,239,250	123,431	64,313	28,359	397	1,399,032
Accumulated Depreciation of Water Plant	4,685	341	—	—	1	5,027
Accumulated Depreciation of Transit Plant	150	39	—	—	—	189
Total Accumulated Depreciation	$1,244,085	$123,811	$64,313	$28,359	$ 398	$1,404,248

(1) Principally due to the purchase of transportation equipment previously leased.
(2) Principally due to capitalization of leases at December 31, 1980.

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DUKE POWER COMPANY

SCHEDULE VIII—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(Dollars in thousands)

Description	Balance Beginning of Year	Charged To Costs and Expenses	Deductions	Balance End of Year
For the Year Ended December 31, 1981				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 4,064	$4,184	$4,250(1)	$ 3,998
Other Reserves				
Operating Reserves(3)	$11,085	$3,243	$2,059(2)	$12,269
For the Year Ended December 31, 1980				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 4,131	$3,402	$3,469(1)	$ 4,064
Other Reserves				
Operating Reserves(3)	$ 9,531	$3,266	$1,712(2)	$11,085
For the Year Ended December 31, 1979				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 3,608	$3,554	$3,031(1)	$ 4,131
Other Reserves				
Operating Reserves(3)	$ 7,604	$3,813	$1,886(2)	$ 9,531

(1) Uncollectible accounts written off, net of recoveries.

(2) Entries represent payments primarily for injuries and damages in North Carolina and South Carolina.

(3) Consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits," on the Balance Sheets.

SCHEDULE X—SUPPLEMENTARY INCOME STATEMENT INFORMATION

	Year Ended December 31		
	1981	1980	1979
	(Dollars in thousands)		
Taxes, other than payroll and income taxes:			
Real and personal property	$ 34,292	$ 32,783	$ 30,736
State and city franchise	85,296	75,264	67,308
Other	6,399	6,208	5,814
Total	$125,987	$114,255	$103,858

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EXHIBIT I

DUKE POWER COMPANY

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE—(Unaudited)

This calculation is submitted in accordance with Release No. 9083 under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	Year Ended December 31		
	1981	1980	1979
	(Dollars in thousands except per share figures)		
Fully Diluted:			
Earnings applicable to common stock(1)	$278,356	$252,479	$222,198
Add: Dividends on Preference Stock, 6¾% Convertible Series AA	1,158	1,919	2,564
Earnings as adjusted for computation	$279,514	$254,398	$224,762
Average common shares outstanding—twelve months (thousands)	87,313	81,985	77,168
Add: Common shares required for conversion of Preference Stock, 6¾% Convertible Series AA, $100 par, 500,000 shares authorized (136,109 shares outstanding as of December 31, 1981)(2)	570	873	1,359
Common shares as adjusted for computation	87,883	82,858	78,527
Fully diluted earnings per share	$3.18	$3.07	$2.86

(1) These figures agree with the related amounts in the Statements of Income.

(2) The conversion price used to convert the Preference Stock, 6¾% Convertible Series AA, into shares of common stock was $23.89 for 1981 and 1980 and $24.73 for 1979.

PART III.

Item 9. *Directors and Executive Officers of the Registrant.*

Information for this item concerning directors of the Company is set forth in the section entitled "Election of Directors" in the proxy statement of the Company relating to its 1982 annual meeting of shareholders, which is incorporated herein by reference.

Information concerning the executive officers of the Company is set forth on page 17 of this annual report.

Item 10. *Management Remuneration and Transactions.*

Information for this item is set forth in the section entitled "Remuneration of Directors and Officers" in the proxy statement of the Company relating to its 1982 annual meeting of shareholders, which is incorporated herein by reference.

PART IV.

Item 11. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K.*

Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Financial Statements
- Statements of Income for the Three Years Ended December 31, 1981
- Statements of Source of Funds for Plant Construction Costs for the Three Years Ended December 31, 1981
- Balance Sheets—December 31, 1981 and 1980
- Statements of Capitalization—December 31, 1981 and 1980
- Statements of Retained Earnings for the Three Years Ended December 31, 1981
- Notes to Financial Statements

Supplemental Financial Data (Unaudited)

Supplemental Schedules
- Schedule V—Property, Plant and Equipment for the Years Ended December 31, 1981, 1980 and 1979
- Schedule VI—Accumulated Depreciation and Amortization of Property, Plant and Equipment for the Years Ended December 31, 1981, 1980 and 1979
- Schedule VIII—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 1981, 1980 and 1979
- Schedule X—Supplementary Income Statement Information for the Years Ended December 31, 1981, 1980 and 1979

Exhibit I—Computation of Fully Diluted Earnings Per Share (Unaudited)

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

Financial statements and schedules of the Company's subsidiaries are omitted because all such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Exhibits
- (a) —See Exhibit Index on page 47.
- (b) —Annual Report on Form 11-K with respect to the Stock Purchase-Savings Program for Employees of the Company for the fiscal year ended October 31, 1981 and the Employees' Stock Ownership Plan for the year ended December 31, 1981.

Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1981.

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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 in the City of Charlotte and State of North Carolina on the 26th day of March, 1982.

DUKE POWER COMPANY
(Registrant)

By: CARL HORN, JR.
Chairman of the Board

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
CARL HORN, JR.	Chairman of the Board (Principal Executive Officer)	March 26, 1982
W. H. GRIGG	Senior Vice President, Legal and Finance (Principal Financial Officer)	March 26, 1982
PORTER A. HAUSER	Vice President and Controller (Principal Accounting Officer)	March 26, 1982
NAOMI G. ALBANESE D. W. BOOTH ROBERT C. EDWARDS ALESTER G. FURMAN III W. H. GRIGG PAUL H. HENSON GEORGE R. HERBERT JOHN D. HICKS HOWARD HOLDERNESS CARL HORN, JR. W. S. LEE BUCK MICKEL REECE A. OVERCASH, JR. WARREN H. OWEN MARSHALL I. PICKENS MACEO A. SLOAN A. C. THIES WILLIAM L. WATKINS	A majority of the Directors	March 26, 1982

LEWIS F. CAMP, JR., by signing his name hereto, does hereby sign this document on behalf of the issuer and on behalf of each of the above-named persons pursuant to powers of attorney duly executed by the issuer and such persons, filed with the Securities and Exchange Commission as supplemental information.

Lewis F. Camp, Jr., Attorney-in-fact

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CONSENT OF INDEPENDENT AUDITORS

Duke Power Company:

We hereby consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement No. 2-71157 on Form S-16 and in Registration Statement No. 2-72172 on Form S-8 of our opinion dated February 15, 1982 appearing in this Annual Report on Form 10-K of Duke Power Company for the year ended December 31, 1981.

Deloitte Haskins & Sells
DELOITTE HASKINS & SELLS

Charlotte, North Carolina
March 26, 1982

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EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit Number	
3-A	—Restated Charter of registrant, dated as of January 1, 1979 (filed with Form S-7, File No. 2-63592, effective March 14, 1979, as Exhibit 2-B-1).
*3-B	—Articles of Amendment to the Articles of Incorporation dated May 4, 1981.
3-C	—Statement of Classification of Shares relating to the 8.84% Cumulative Preferred Stock, Series N (filed with Form S-16, File No. 2-66561, effective February 6, 1980, as Exhibit 2-B-3).
3-D	—Statement of Classification of Shares relating to the 11% Cumulative Preferred Stock, Series O (filed with Form S-16, File No. 2-68582, effective August 19, 1980, as Exhibit 2-B-3).
3-E	—Statement of Classification of Shares relating to the 15.40% Preferred Stock A, 1982 Series (filed with Form S-16, File No. 2-75953, effective February 23, 1982, as Exhibit 2-B-5).
*3-F	—By-Laws of registrant, as amended to date.
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-3	—Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).
4-B-4	—Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12	—Supplemental Indenture, dated as of April 1, 1951, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13	—Supplemental Indenture, dated as of September 1, 1953, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-15	—Supplemental Indenture, dated as of January 1, 1955, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).
4-B-16	—Supplemental Indenture, dated as of May 1, 1956, supplementing said Mortgage (filed with Form S-9, File No. 2-12402, effective April 26, 1956, as Exhibit 2-B-16).
4-B-17	—Supplemental Indenture, dated as of January 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).

Exhibit Number	
4-B-18	—Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-19	—Supplemental Indenture, dated as of February 1, 1962, supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).
4-B-20	—Supplemental Indenture, dated as of August 1, 1962, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).
4-B-21	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-20).
4-B-22	—Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).
4-B-23	—Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15,1968, as Exhibit 2-B-25).
4-B-24	—Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).
4-B-25	—Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).
4-B-26	—Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).
4-B-27	—Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).
4-B-28	—Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).
4-B-29	—Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).
4-B-30	—Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effective March 7, 1972, as Exhibit 2-B-30).
4-B-31	—Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).
4-B-32	—Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).
4-B-33	—Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).
4-B-34	—Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).
4-B-35	—Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).
4-B-36	—Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).
4-B-37	—Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).
4-B-38	—Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).
4-B-39	—Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).
4-B-40	—Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).
4-B-41	—Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).

Exhibit Number	
4-B-42	—Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).
4-B-43	—Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-68571, effective August 19, 1980, as Exhibit 2-B-43).
4-B-44	—Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).
4-B-45	—Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-K, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).
4-B-46	—Indenture, dated as of September 1, 1957, between the registrant and Chemical Corn Exchange Bank, Trustee, covering 4⅞% Sinking Fund Debentures due September 1, 1982 (filed with Form S-9, File No. 2-13526, effective September 4, 1957, as Exhibit 2-B-17).
4-B-47	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Indenture (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-23).
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated as of August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated as of October 14, 1980, between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated as of October 14, 1980, between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

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WARNING
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DUKE POWER COMPANY

FORM 10-K

ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION FOR THE YEAR ENDED DECEMBER 31, 1982

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PART I.

Item 1. *Business.*

DUKE POWER COMPANY

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,000,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1982, the Company's electric revenues amounted to approximately $2.2 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks ninth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242 (Telephone No. 704-373-4011).

Factors Affecting the Industry. The electric utility industry in general has been experiencing problems in a number of areas including difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; difficulty in obtaining sufficient capital on reasonable terms; the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

For a discussion of the developments affecting the Company, see "Construction Program" (pages 2 through 5), "Business—Rate Matters" (pages 7 and 8), "Business—Fuel Supply" (pages 8 through 10), "Business—Regulation—*Environmental Matters*" (pages 10 through 12) and "Business—Regulation—*Nuclear Facilities*" (pages 12 and 13).

FINANCING PROGRAM

The Company estimates that it will obtain through the sale of securities and other external sources at least 30% of its 1983-1985 total capital requirements, which include cost estimates of $1.9 billion for the construction program, $581 million for nuclear fuel, $57 million for the refunding of maturing long-term debt and sinking fund requirements and approximately $114 million related to maturities with respect to capitalized nuclear fuel trusts. The balance of such requirements is expected to be obtained from retained earnings, depreciation and amortization, deferred taxes, investment tax credit and other internal sources. Such expectation is based in part upon receiving future rate increases as to which no assurance can be given. During 1983, the Company proposes to borrow the proceeds of the sale of approximately $100 million principal amount of pollution control revenue bonds to be issued by Oconee County, South Carolina, subject to a favorable ruling of the Internal Revenue Service and certain other contingencies. The Company also has an effective registration statement under Rule 415 of the Securities Act of 1933 for the possible issuance during 1983 of up to $50 million of Preferred Stock A ($25 par value). The types, amounts and timing of sales of additional securities will depend upon market conditions and other factors.

The foregoing estimates of the Company's capital requirements expected to be obtained from external sources do not give effect to the proceeds of the proposed sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to Piedmont Municipal Power Agency (PMPA), a joint agency formed by a group of the Company's South Carolina municipal customers, as described under "Facilities Under Construction." Such sale would reduce the amount of external financing required by the Company by the amount initially received and by the amounts of progress payments to be made as additional construction costs are incurred. The sale, which is contingent upon the arrangement of necessary financing by PMPA and subject to other contingencies, has been delayed by an appeal from an order of The Public Service Commission of South Carolina (PSC) authorizing the transaction. The Company has no assurance that such sale will be consummated.

While the Company has budgeted for certain contingencies, including potential cancellation charges related to Cherokee Unit 2, it has no assurance that budgeted contingencies will fully cover ultimate cancellation costs. The budgeted capital requirements do not give effect to any change in the status of construction of Cherokee Unit 1. See "Construction Program."

In order to issue additional mortgage bonds and preferred stock, the Company must comply with earnings coverage and assets requirements contained in its mortgage indenture and articles of incorporation. Under the provisions of such indenture, additional bonds (other than certain types of refunding bonds) may not be issued unless the Company's available net earnings (as defined) for 12 consecutive calendar months within the 15 calendar months immediately preceding shall have been at least twice the amount of the annual interest charges on all bonds outstanding and applied for under the indenture. Additional bonds may be issued only against cash, certain retired bonds and in the amount of 66⅔% of the aggregate of the net amounts of additional property certified to the trustee pursuant to the indenture.

Under its articles of incorporation, the Company may not issue additional shares of preferred stock unless, after giving effect thereto, (i) its net earnings available for dividends on the preferred stock for any 12 consecutive calendar months within the 15 calendar months preceding the month in which the additional shares are to be issued shall have been at least twice the dividend requirements for a 12-month period upon the entire amount of preferred stock and all other stock ranking prior to or on a parity with the preferred stock, and (ii) the total net assets of the Company at a date not more than 90 days prior to the date on which the additional shares are to be issued shall equal at least twice the aggregate amount payable upon the involuntary liquidation of the Company to the holders of the preferred stock and all other stock ranking prior to or on a parity with the preferred stock.

On the basis of these requirements, the Company's interest and dividend coverages for the years shown were as follows:

	Year Ended December 31		
	1982	1981	1980
Mortgage bond interest	3.60	2.61	2.73
Preferred stock dividends	5.61	5.96	5.45

As of December 31, 1982, the Company could have issued under the earnings test contained in its mortgage indenture approximately $1.5 billion principal amount of additional bonds, assuming an interest rate of 12½%. As of such date the Company could have issued approximately $840 million of additional preferred stock within the above restrictions contained in its articles of incorporation.

CONSTRUCTION PROGRAM

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rate increases), the availability and cost of capital in the financial markets, the availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise (see "Opposition to Nuclear Power Development") and changing regulatory and environmental standards (see "Business—Regulation—*Environmental Matters*"). The estimates of construction costs and the timing of construction expenditures are also subject to the sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to PMPA. The Company is keeping its construction program as flexible as possible in order to accommodate any variations as a result of such considerations.

Construction of Unit 1 of the Cherokee Nuclear Station has continued on a limited basis since February 1981 when the Board of Directors ordered a reduction in the pace of construction of this Unit because of difficulties in attracting capital on reasonable terms.

In November 1982, because of lower growth in demand than when initially planned, the Board of Directors announced the cancellation of Units 2 and 3 of the Cherokee Nuclear Station. The Company has spent approximately $70 million on such canceled units and has contractual commitments relating to Unit 2. Significant costs relating to the cancellation of such commitments will be incurred. However, the amount of such costs cannot be determined pending negotiations with suppliers. No such contractual commitments have been made for the proposed Unit 3. Precedents for recovery of all costs related to the canceled units exist in all of the Company's regulatory jurisdictions. In its latest rate order, the PSC authorized the Company to recover over a ten-year period costs allocated to such Units through June 30, 1982 related to the South Carolina retail jurisdiction. The Company presently has pending before the North Carolina Utilities Commission (NCUC) a request to recover such costs related to that jurisdiction.

Estimated Costs

Cost estimates for the construction program, including the acquisition of nuclear fuel, for each of 1983, 1984 and 1985 and for the three-year period 1983-1985, as now scheduled, assuming no further sale of the Company's remaining interest in the Catawba Nuclear Station, are as follows (in millions of dollars):

Type of Facilities	1983	1984	1985	Total
Generation*	$473	$395	$291	$1,159
Transmission	45	54	45	144
Distribution	140	159	168	467
Other	54	62	44	160
Total	$712**	$670**	$548**	$1,930**
Nuclear Fuel	$124	$214	$243	$ 581

* Cost estimates for the three-year period 1983-1985 include approximately $200 million attributable to the portion of the Catawba Nuclear Station which the Company has agreed to sell to PMPA. Such estimates also include approximately $200 million to continue construction of Unit 1 of the Cherokee Nuclear Station. (See "Facilities Under Construction.")

** The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation utilizing Bureau of Labor Statistics indices.

The Company is continuing to experience higher costs of construction of new facilities as a result of recurring increases in the costs of materials, labor and capital, and increasing capital commitments attributable to more stringent regulatory requirements. However, the Company believes that in recent years it has been able to construct generating units at a lower cost per KW than generally experienced by other utilities for units of comparable type and vintage.

During the three-year period 1980-1982, gross property additions (including nuclear fuel) and net retirements amounted to approximately $2.4 billion and $500 million, respectively, resulting in a net increase of approximately $1.9 billion, or 29%, in gross plant. Net retirements include the portions of the Catawba Nuclear Station sold to certain of the Company's cooperative customers (see "Facilities Under Construction").

Facilities Under Construction

The following table sets forth the major generating facilities of the Company currently under construction which are to be added to its present generating capability of 13,411,000 KW:

Unit and Location	Net KW Capability	Energy Source	Company Ownership (%)	Date of Planned Operation(1)	Estimated Construction Cost per KW(2)	Total Estimated Construction Costs(2)	Amounts Expended Through 1982(2)
						(Dollars in millions)	
McGuire 2 (Northwest of Charlotte, in North Carolina)	1,180,000	Nuclear	100	1984(3)	$ 843	$1,988(4)	$1,805(4)
Catawba 1	1,145,000	Nuclear	25	1985	1,703(5)	975(5)	490(5)
Catawba 2 (Southwest of Charlotte, in South Carolina)	1,145,000	Nuclear	25	1987	1,703(5)	975(5)	490(5)
Cherokee 1 (Northeast of Spartanburg, in South Carolina)	1,280,000	Nuclear	100	(6)	(6)	(6)	538
Bad Creek(7) (Oconee County, South Carolina)	1,000,000	Hydro	100	(7)	861	861	22

(1) Based on past experience, operational dates may vary due to construction delays, difficulties which may be encountered in obtaining regulatory approvals or in obtaining capital at reasonable costs, changes in load forecasts and other factors (see "Business—Regulation").

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(2) These amounts exclude the costs of initial fuel cores.

(3) Unit 2 of the McGuire Nuclear Station, previously scheduled for completion in 1983, is currently scheduled for completion in early 1984. The Nuclear Regulatory Commission issued an operating license for such Unit on March 3, 1983 and fuel loading has been completed.

(4) Unit 1 of the McGuire Nuclear Station commenced commercial operation on December 1, 1981. The Company prepares cost estimates on a total station basis and estimated construction costs and amounts expended include all costs related to both Units.

(5) These amounts do not include the costs of the undivided interests sold to the North Carolina Municipal Power Agency Number 1 in 1978 and to groups of the Company's cooperative customers in 1981, and assume no further sale of the Company's remaining interest in the Catawba Nuclear Station.

(6) Unit 1 of the Cherokee Nuclear Station, previously scheduled for completion in 1990, has been delayed indefinitely due to difficulties in attracting the necessary capital on reasonable terms. Work on such Unit has been substantially reduced while the Company fully evaluates its long-term options with respect to such Station. Although this delay may result in near-term reductions in expenditures, cost escalation and inflationary trends will, over the long term, increase construction costs should this facility be rescheduled and constructed at a later date.

(7) The Bad Creek Hydroelectric Station, a pumped storage facility, will consist of four 250,000 KW units. Although construction completion has not been definitely scheduled, the above cost estimates assume commercial operation dates of 1990 for two units and 1991 for the remaining two units.

In order to reduce its need for external financing, the Company, in 1978, sold to the North Carolina Municipal Power Agency Number 1 (NCMPA), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. In 1981, the Company also sold to groups of its North Carolina and South Carolina cooperative customers a 75% undivided interest in Unit 1 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. The Company will continue to construct the facility and the purchasers will finance their respective portions of the construction costs by continued monthly progress payments.

The transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also provide for the maintenance by the Company of a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station. NCMPA has given the required six months notice that it would invoke this provision effective July 1, 1983, thereby making NCMPA an operating entity serving its municipal customers. The Company does not anticipate that the implementation of this provision will have a material effect on earnings.

The Company and PMPA have an agreement with respect to the purchase by PMPA of the remaining 25% interest in Unit 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to NCMPA. However, the Company has no assurance that such sale will be consummated.

During 1982, NCMPA's participating municipalities, which are presently wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and PMPA's participating municipalities accounted for approximately 2% of KWH sales and approximately 2% of revenues. The purchasers of a portion of Unit 1 accounted for approximately 7% of KWH sales and approximately 6% of revenues.

The application for operating licenses for the Catawba Nuclear Station has been filed by the Company and docketed by the Nuclear Regulatory Commission (NRC). Subsequent to the docketing, the Atomic Safety and Licensing Board granted several petitions to intervene in the licensing proceeding and a hearing will be required.

Load Management

The Company currently is engaged in a comprehensive load management program designed to reduce the growth in peak demand without restricting the continued economic development of the Company's service area. Such program includes, among other things, promotion of energy-efficient building structures and appliances, use of residential conservation rates, use of interruptible rates for large customers, control by the Company (with customers' consent) of residential electric water heaters and air conditioners during peak demand periods and time-of-day pricing to a limited number of customers. The current and planned aspects of such program are designed to reduce the growth in peak demand by approximately 4,052,000 KW in the summer of 1997 (from estimated peak demands at those times without load management) and to enhance generating reserve margins through the ability to interrupt approximately 1,141,000 KW in 1997. The Company has currently documented reductions through accumulated load management of approximately 1,065,500 KW for its summer peak load and approximately 1,399,870 KW for its winter peak load.

Through 1990, the Company estimates a minimum reserve margin, after giving effect to the interruptible load, of approximately 22% of its anticipated peak load requirements. (For information about the Company's peak loads, see "Business—Energy Requirements and Capability.")

General

The complexity of present-day electric utility technology and the time required for the construction of generating facilities and for the completion of the licensing and other regulatory proceedings relating thereto have compelled the Company, as well as other electric utilities, to make substantial investments in the construction of such facilities prior to the completion of licensing and regulatory proceedings. At February 28, 1983, the Company had approximately $1.1 billion invested in its portion of the Catawba Nuclear Station and Unit 1 of the Cherokee Nuclear Station, for which operating licenses have not been issued. Under present NRC procedures, an operating license may be issued only when construction of a nuclear unit has been completed. Accordingly, the Company is necessarily making substantial investments in its facilities before regulatory proceedings are completed. There is no assurance that the necessary operating licenses and authorizations will be issued for such facilities.

Opposition to Nuclear Power Development

The development of nuclear power continues to be a subject of public controversy. Various groups have engaged in public protests, filed suits and participated in administrative proceedings and other activities, claiming that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. In addition, restrictive legislation relating to nuclear power has been proposed in Congress and in several state legislatures and referenda have been proposed to the electorate in certain states. Some of the claims made by such groups, if they should prevail, or the existence of the controversy itself, could delay or prevent the construction of nuclear generating units presently under construction, or cause substantial modifications to or shutdowns of existing units.

The Company's studies continue to support its conclusion that the generation of electricity by nuclear power will be more economical than generation by fossil fuel, and the Company believes that its present construction program is compatible with the protection of the environment.

BUSINESS

Service Area

The Company supplies electric service directly to approximately 1,322,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to 37 other incorporated municipalities and to a number of rural electric cooperatives and private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco, furniture and chemical industries are of major significance to the economy of the area, and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, food products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $336 million of the Company's revenues for 1982, representing 15% of electric revenues and 47% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1982, its generation of electric energy for 1982, and certain corresponding information presently projected for 1983:

			Generating Capability(1)			Generation		
			Actual 1982		Projected 1983(2)	Actual 1982		Projected 1983(2)(3)
Source	Facility		KW	%	%	KWH (millions)	%	%
Coal	Belews Creek		2,240,000			13,351		
	Marshall		1,900,000			12,706		
	Allen		1,100,000			4,945		
	Cliffside		770,000			3,082		
	Others		1,413,000			4,843		
		Total	7,423,000	56.1	57	38,927	70.1	59
Nuclear	Oconee		2,580,000			10,707		
	McGuire		1,180,000			4,302		
		Total	3,760,000	28.4	28	15,009	27.1	38
Hydro	26 stations		1,452,000	11.0	11	1,569	2.8	3
Oil and Gas	Combustion turbines		599,000	4.5	4	7	—	—
		Total	13,234,000	100.0	100	55,512	100.0	100

(1) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(2) Projected figures are based on the assumption that required fuel is available and that there are no unforeseen contingencies. Effective January 1, 1983 certain coal-fired units were upgraded, increasing total capability to 13,411,000 KW.

(3) Generating output, after giving effect to the implementation of the McGuire reliability exchange, is projected to be 60% coal, 37% nuclear and 3% hydro. (See "Construction Program.")

According to industry statistics through 1981, the Company ranked first in the nation for the last eight consecutive years and for ten of the last twelve years in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that Marshall and Belews Creek Steam Stations were the first and second most efficient in the nation in 1981. A Company station has been ranked first in efficiency in 14 of the last 16 years through 1981. Statistics supplied to the NRC by utilities demonstrate that the Company's Oconee Nuclear Station was the most efficient pressurized water reactor nuclear facility in the nation in 1981. The net capacity factors for the Oconee Nuclear Station were 63% for 1980, 61% for 1981 and 47% for 1982. The reduction in the net capacity factor for 1982 was primarily due to planned ten-year inspection outages.

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The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1982-1983 winter peak load of 10,378,000 KW occurred on January 19, 1983, and the 1982 summer peak load of 10,097,000 KW occurred on July 28, 1982. The 1981-1982 winter peak load of 11,145,000 KW occurred on January 11, 1982, and the 1981 summer peak load of 10,602,000 KW occurred on August 5, 1981. The Company has reduced its peak load growth forecast through 1996 to 2.8%, compounded annually, from 3.8%.

Federal Energy Legislation

Congress adopted a national energy act in 1978 dealing with, among other things, utility rate design, including restrictions on the use of fuel adjustment clauses. Other sections of the legislation give the Federal Energy Regulatory Commission (FERC) increased authority to order interconnections, power pooling and wheeling of power. The Company is presently unable to assess the impact of this legislation on its operations.

Rate Matters

The NCUC and the PSC must approve the Company's rates for retail sales within the respective States. FERC must approve the Company's rates for sales under its wholesale rate schedules.

General Rate Increases. The following table sets forth information concerning all rate increases requested or implemented by the Company since January 1, 1980. The revenues (in millions of dollars) shown are annualized on the basis of the filing test year.

Jurisdiction and Date Filed(1)	Requested Revenues	Approved Revenues	Approved % of Request	Approved % of Increase Over Previous Revenues	Rate Order Effective	End of 12-Month Test Period
N. C. Retail:						
February 1980	$ 91.6	$ 57.5	62.7	6.0	October 1980	December 31, 1979
March 1981(2)	211.0	166.4	78.9	14.99	December 1981	December 31, 1980
March 1982	197.0	61.7	31.3	4.38	November 1982	December 31, 1981
February 1983	112.9	—	—	—		
S. C. Retail:						
August 1979(3)	25.8	23.4	90.5	6.0	September 1980	June 30, 1979
December 1980	103.7	57.0	54.9	13.0	January 1982	December 31, 1980
February 1982(4)	99.4	40.7	40.9	7.1	March 1983	June 30, 1982
FERC Wholesale:						
June 1980	26.3	18.6	70.7	8.9	February 1981	December 31, 1981
June 1981	46.9	30.7	65.5	11.9	August 1982	September 30, 1982
August 1982(5)	44.1	—	—	—		

(1) In the past, the Company has collected interim rate increases, subject to refund, in all three jurisdictions and is currently collecting on that basis from its wholesale customers. On occasion the Company has implemented its entire request on such a basis prior to the final rate order.

(2) Intervenors appealed this order on various grounds, seeking its reversal or modification and refunds. The order has been appealed to the North Carolina Court of Appeals.

(3) Intervenors appealed this order on various grounds, seeking its reversal or modification and refunds of amounts paid to the Company pursuant to its provisions. The Court of Common Pleas, Richland County, upheld the order and it has been appealed to the South Carolina Supreme Court.

(4) On March 25, 1983, the Company filed a petition for rehearing or reconsideration with the PSC.

(5) This request was based on general parity between rates of return for the Company's wholesale customers and its North Carolina retail industrial customers. This request was subsequently revised to $26 million to reflect a settlement agreement between the Company and its wholesale customers.

The Company has not been able to earn the rates of return as allowed and defined by the NCUC and the PSC in recent rate proceedings since orders resulting therefrom were based on historical cost during inflationary periods. In the Company's most recent rate proceedings, the NCUC allowed a jurisdictional rate of return on common equity of 15.22%, and the PSC allowed a jurisdictional rate of return on common equity of 13%.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The procedures for wholesale customers entail a 90-day lag from the date changes occur until they are reflected in bills to such customers.

The fuel cost recovery procedures for South Carolina retail customers set the base fuel factor semiannually after a public hearing to review fuel costs. The semiannual review takes into consideration fuel costs experienced in the past as well as fuel costs projected for the subsequent six months.

In June 1982 the North Carolina General Assembly enacted legislation revising the statute under which the NCUC adjusts base rates to reflect fuel costs. The new statute, among other things, requires that such costs be reviewed within one year of the resolution of a general rate case. The NCUC issued an order on December 22, 1982 for the purpose of instituting a rule-making proceeding for the implementation of the new statute.

Intervenors have appealed an order of the NCUC dated February 26, 1982 adjusting rates based on changes in fuel cost, seeking its reversal or modification and refunds.

Construction Work in Progress. In June 1982 the North Carolina General Assembly revised the statute under which the NCUC had been required to accept in rate base all CWIP submitted in rate applications related to expenditures made after June 30, 1979. The new statute permits the NCUC at its discretion to include such CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The Company currently has $276 million of CWIP in the rate base in its North Carolina retail jurisdiction. The NCUC has instituted a rule-making proceeding to determine what guidelines, if any, for inclusion of CWIP in rate base should be adopted for electric utilities.

Fuel Supply

The Company presently relies principally on coal for the generation of electric energy, but it anticipates relying on nuclear power to a greater extent in the future (see "Construction Program"). The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source			Average Cost per Million BTU on a Burned Basis		
	Year Ended December 31			Year Ended December 31		
	1982	1981	1980	1982	1981	1980
Coal	70.1%	73.6%	71.6%	190.87¢	178.39¢	155.64¢
Nuclear	27.1	24.6	24.8	55.04	48.98	48.22
Oil and Gas	—	.3	.4	439.40	416.17	300.16
All Fuels (cost based on weighted average)	97.2	98.5	96.8	149.86	144.33	127.00
Hydroelectric*	2.8	1.5	3.2			
	100.0%	100.0%	100.0%			

* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

Coal. The Company obtains its coal under long-term supply contracts with mining operators utilizing both deep and surface mining, through its own mining operations, all of which are deep mine, and by open market purchases. During 1982, the Company obtained its coal requirements approximately as follows: 70% (11.7 million tons) under long-term contracts, 15% (2.6 million tons) from its own mining operations and 15% (2.5 million tons) by open market purchases. On March 17, 1983, the Company had on hand a coal supply of approximately 97 days.

The Company is presently negotiating for the sale of all of its mining operations and, in anticipation of such disposition, a provision for a loss of $30 million was recorded net of applicable income taxes in December 1982. To date, the Company has entered into a contract for the sale of its Arjay mine in Kentucky. The Company intends to replace the coal from these operations through additional long-term contracts and open market purchases. The Company determined to sell these properties after the NCUC in its most recent rate order limited the cost of coal from these operations which may be included in rates to the maximum long-term contract price from unaffiliated sources.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1983 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. In order to further assure its coal supply, the Company has invested in independent coal mining operations located in eastern Kentucky.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. In 1982, the Company purchased coal on a spot basis at an average delivered cost of $36.93 per ton, or 152.5¢ per million BTU as compared with an average delivered cost of $42.60 per ton, or 176.1¢ per million BTU, for the year 1981.

The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the emission limitation for sulfur dioxide for existing facilities (see "Regulation—*Environmental Matters*").

The Company estimates that through the year 2000 its existing coal-fired generating units (see table under "Energy Requirements and Capability") will burn a total of approximately 250 million tons of coal. The Company presently expects to obtain the major portion of this estimated requirement from long-term agreements.

The Economic Regulatory Administration of the Department of Energy is authorized, under prescribed conditions, to allocate coal to achieve, among other things, the distribution of available low sulfur fuels on a priority basis to areas designated by the United States Environmental Protection Agency (EPA).

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations (see "Energy Requirements and Capability" and "Construction Program") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1993	1993	2009	1989
McGuire	1993	1993	2009	1989
Catawba	1993	1993	2009	1989

Approximately 75% of the Company's commitments for uranium materials included in the preceding table is expected to be obtained from Rio Algom, Ltd., a Canadian supplier. Deliveries to the Company by such supplier, which began in 1981, are subject to permits and export licenses from various Canadian governmental agencies, including the Atomic Energy Control Board, the Department of Industry, Trade and Commerce and the Uranium Exports Review Panel.

The Company purchased uranium material during 1982 at an average price of approximately $34 per pound. However, such price is expected to be greater in future years. The Company's material nuclear supply contracts generally contain *force majeure* provisions and provide for price escalation under certain conditions.

As a part of the Company's efforts to obtain additional sources of uranium at a reasonable cost, a wholly-owned subsidiary of the Company, Western Fuel, Inc., entered into a joint venture in central Wyoming. The Company has expended approximately $12 million, including capital costs, in connection with the venture. In August 1981 the joint venture began commercial production. As a result of certain geological problems in the mining process, the cost per pound of uranium produced exceeded expectations. The additional cost required to resolve such problems, coupled with a declining uranium market, led to curtailment of operations. In September 1982 operations were suspended and the Company currently does not anticipate any further uranium production from the venture.

Although the reprocessing of spent fuel could make available to the Company an additional 20% of its nuclear fuel needs through 1990, there are currently no commercial reprocessing facilities in operation in the United States. The utilization of such facilities is dependent upon certain regulatory and policy decisions to be made by the Federal government.

The Company has received regulatory approvals which will enable it to provide adequate storage facilities for its spent nuclear fuel through 1989. The Company also has requested regulatory approval for the installation of redesigned racking in the Oconee Unit 3 spent fuel pool to increase storage capacity, which would extend adequate storage capacity to 1992. Consideration is being given to expanding system storage capacity through 1998 by additional reracking, through transshipment of spent fuel between stations, and through the use of developing storage technologies such as rod consolidation. The Nuclear Waste Policy Act of 1982 requires that the Department of Energy begin disposing of spent fuel not later than January 31, 1998.

See *"Depreciation and Amortization"* under Note 1 of Notes to Financial Statements for additional information regarding nuclear fuel costs.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, EPA and state environmental agencies and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities (see "Construction Program"). The coal mining operations of Eastover Mining Company, the Company's coal mining subsidiary, are subject to the Federal Mine Safety and Health Act of 1977.

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1983-1985 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $193 million, including $75 million in 1983 and $70 million in 1984. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

AIR QUALITY. In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing standards limiting such emissions which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans.

With respect to particulate emissions, the implementation plans require compliance with an opacity standard based on the visual density of the flue gas and a mass emissions standard stated in terms of pounds per million BTU of heat input.

Although the Company believes it has installed the best available control technology in its coal-fired generating stations, it has determined that it could not consistently and continuously meet the stringent mass emission standards of the North Carolina implementation plan even though each unit had successfully completed stack performance tests. The Company filed for a variance from the particulate emission limitations, which was granted by the North Carolina Environmental Management Commission (EMC) in 1979 and approved by EPA in 1980 as a revision to the State's implementation plan. In granting the variance for a three-year period, EMC found that the Company had installed the best available control technology at its coal-fired generating stations and that independent air monitoring and modeling studies indicated that the emission limitations could be modified without violating state and Federal ambient air quality standards. EMC also required that extensive performance tests be completed to determine if a correlation exists between opacity and mass emission standards and to provide data for the setting of a permanent mass emission standard. Under the variance, the interim mass emission standard ranges from 0.20 to 0.25 pounds per million BTU of heat input. The Company has submitted the data resulting from the performance test program and the State has

utilized the data in setting a permanent mass emission standard to replace the variance. The new regulation imposes mass emission limits ranging from 0.12 to 0.25 pounds per million BTU of heat input and stringent annual tonnage emission limits for each boiler unit. The new regulation has been submitted by the State to EPA for approval as a revision to the North Carolina implementation plan.

In 1981, EPA approved a revision to the North Carolina implementation plan which eliminated a previously planned stepdown in the opacity limit for existing coal-fired generating units from 40% to 20%.

Following public notice and hearing, in 1977 EMC approved a revision to the North Carolina regulation limiting emissions of sulfur dioxide from fuel-burning sources and submitted the revision to EPA for review and approval as required by the 1970 Act. The revision to the North Carolina State Implementation Plan eliminated a stepdown in the emission limit from 2.3 pounds to 1.6 pounds per million BTU of heat input which had been previously planned for July 1, 1980. EPA has indicated that it will not enforce the 1.6 pound limit until final agency action is completed on the pending revision. If EPA disapproves the revision, the Company could be compelled to incur large capital costs for pollution control equipment in order to avoid noncompliance penalties. In December 1982, EPA published notice of its approval of this revision with specified exceptions. The Company's Allen and Cliffside Stations were excluded from the approval. The Company has submitted additional data pertaining to these two plants and believes that EPA will approve a proposed 2.3 pound emission limit for the Allen Steam Station and a 2.2 pound emission limit for the Cliffside Steam Station.

In 1974, EPA issued regulations, applicable to the construction or expansion of facilities commenced after June 1, 1975, establishing a mechanism for "prevention of significant air quality deterioration" in areas where air pollution levels of sulfur dioxide and particulate matter are below the national ambient air quality standards. Amendments to the 1970 Act, adopted in 1977, include, among other things, requirements substantially similar to such regulations. The amendments also require EPA to establish stringent restrictions on emissions in non-attainment areas, to update new source performance standards for specified pollutants and to require the use of the best available technology rather than clean fuels to control emissions. The amendments also authorize EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and new civil penalties of up to $25,000 per day for facilities found to be in violation of an applicable implementation plan. EPA has promulgated new source performance standards under these amendments which will apply to all stations not presently under construction and will require the use of scrubbers to remove sulfur dioxides, as well as other techniques to remove nitrogen oxides and particulate matter emissions. These amendments and proposed standards will affect the lead time, size and siting of future fossil-fueled generating stations as well as the type, complexity and cost of pollution control equipment to be used.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1972 (the 1972 Act) provided for the imposition of effluent limitations to regulate discharges of pollutants, including heat, into the waters of the United States. The 1972 Act mandated that there be achieved by July 1, 1977, with respect to existing facilities, effluent limitations requiring application of the "best practicable control technology currently available" as well as compliance with state water quality standards. The Company has complied with these requirements.

The 1972 Act requires permits to ensure compliance with its provisions. The Company has received such permits for all of its generating stations either from EPA or under the permit programs of the States of North Carolina and South Carolina which have been approved by EPA.

In 1974, EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines required certain limitations on chemical discharges and imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit *(Appalachian Power Company, et al. v. Train)*. In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement and certain chemical limitations. The Company is unable at this time to determine what effect these developments will have on its operations.

In 1977, Congress adopted the Clean Water Act of 1977 (the 1977 Act) which amended the 1972 Act. The 1977 Act provided for three categories for controlling pollution: (1) conventional pollutants will require treatment by the best conventional pollutant control technology by July 1, 1984; (2) toxic pollutants will require application of the best available technology economically achievable by July 1, 1984; and (3) non-conventional pollutants will require application of the best available technology economically achievable within three years after effluent limitations are established, but no later than July 1, 1987. The Company will be unable to determine the effect, if any, such legislation will have on its operations until the required regulations are promulgated.

On January 29, 1982, the District Court for the District of Columbia issued a decision (*National Wildlife Federation* v. *Gorsuch*) declaring that the 1972 Act requires permits for dams that discharge pollutants. This decision was appealed and on November 5, 1982 the United States Court of Appeals for the District of Columbia Circuit reversed, holding that permits for discharges from dams are not required by the 1972 Act.

OTHER ENVIRONMENTAL REGULATIONS. North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. North Carolina and South Carolina have adopted regulations implementing the Resources Conservation and Recovery Act and are in compliance with such Act.

Polychlorinated biphenyls (PCBs) are regulated by provisions of the Toxic Substances Control Act. Major portions of the regulations issued by EPA implementing such provisions have been appealed. The Company will be unable to determine the effect, if any, those regulations will have in its operations until the appeal is decided.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, known as "Superfund" became law in 1980. It requires the reporting of releases of hazardous substances into the environment and the notification to EPA of hazardous waste facilities which are not subject to other regulations. The Company has implemented reporting procedures in order to comply with the Act.

GENERAL. The Company cannot estimate the effect of existing and potential regulations upon any of its existing and proposed facilities. However, developments in these and other areas of regulation have in the past required the Company to modify or replace equipment and may in the future delay construction and operation of new or existing facilities at costs which could be substantial.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations currently permit public intervention with respect to issuances of permits and licenses.

The NRC recently requested the Company to study its Oconee reactor vessels for thermal shock effects of emergency core cooling system operations during a loss of feedwater event, as well as other transients which might induce rapid overcooling of the system. Preliminary analyses of the Oconee units conducted by the Company and the manufacturer, Babcock & Wilcox Company, have indicated that the vessels as constructed are adequate to permit safe operation for the remainder of their projected 40-year lives. The present position of the staff of the NRC is that the units can operate safely pending completion of its analysis of the matter. However, should modification be warranted upon completion of analyses, the cost of such modification is not expected to be material.

Vibration problems involving steam generator tubes near the feedwater inlet have been experienced in two European units similar to McGuire Unit 1 and slight evidence of wear was found at the McGuire unit. The unit was operated at approximately 50% of capacity while the Company and the manufacturer evaluated the situation and determined the appropriate corrective measures. The unit was taken out of service in mid-January 1983 for corrective measures which are expected to require the unit to be out of service until late April 1983. Similar modifications will be made to the McGuire Unit 2 steam generator.

The Company has insured against public liability claims resulting from nuclear incidents to the full $560 million limit on liability under the Price-Anderson Act. The maximum available private insurance of $160 million has been purchased and the remaining $400 million has been provided through a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors, and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance coverage does not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $500 million, or the insurable value of the facilities, whichever is less. The Company has purchased from Nuclear Electric Insurance Limited (NEIL), a Bermuda mutual insurance company, of which it is a member, an additional $415 million of property damage insurance through its Excess Property Insurance Program. The Company also has purchased an additional $68 million of property damage insurance through a pool of stock and mutual insurance companies. In connection with the sale in 1978 of a portion of its interest in the Catawba Nuclear Station (see "Construction Program"), the Company placed through a pool of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of $460 million.

NEIL also provides insurance against the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. The Company's Oconee Nuclear Station and Unit 1 of the McGuire Nuclear Station are insured for up to $2.5 million a week per unit, after a 26-week deductible period, with declining amounts per unit where more than one unit is involved. Coverages continue at 100% for 52 weeks and at 50% for an additional 52 weeks. This is presently the maximum amount of coverage available.

Reference is made to Note 13 of Notes to Financial Statements for information concerning potential retrospective premium adjustments.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which the Company considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

Employees

At December 31, 1982, the Company employed approximately 20,300 persons, of whom approximately 7,700 were engaged in generating plant construction including design and engineering. About 1,850 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW) with which the Company has a labor agreement which expires on September 30, 1983.

The Company's coal mining subsidiary, Eastover Mining Company, employs approximately 1,200 persons, the majority of whom is represented by labor unions, including the United Mine Workers of America.

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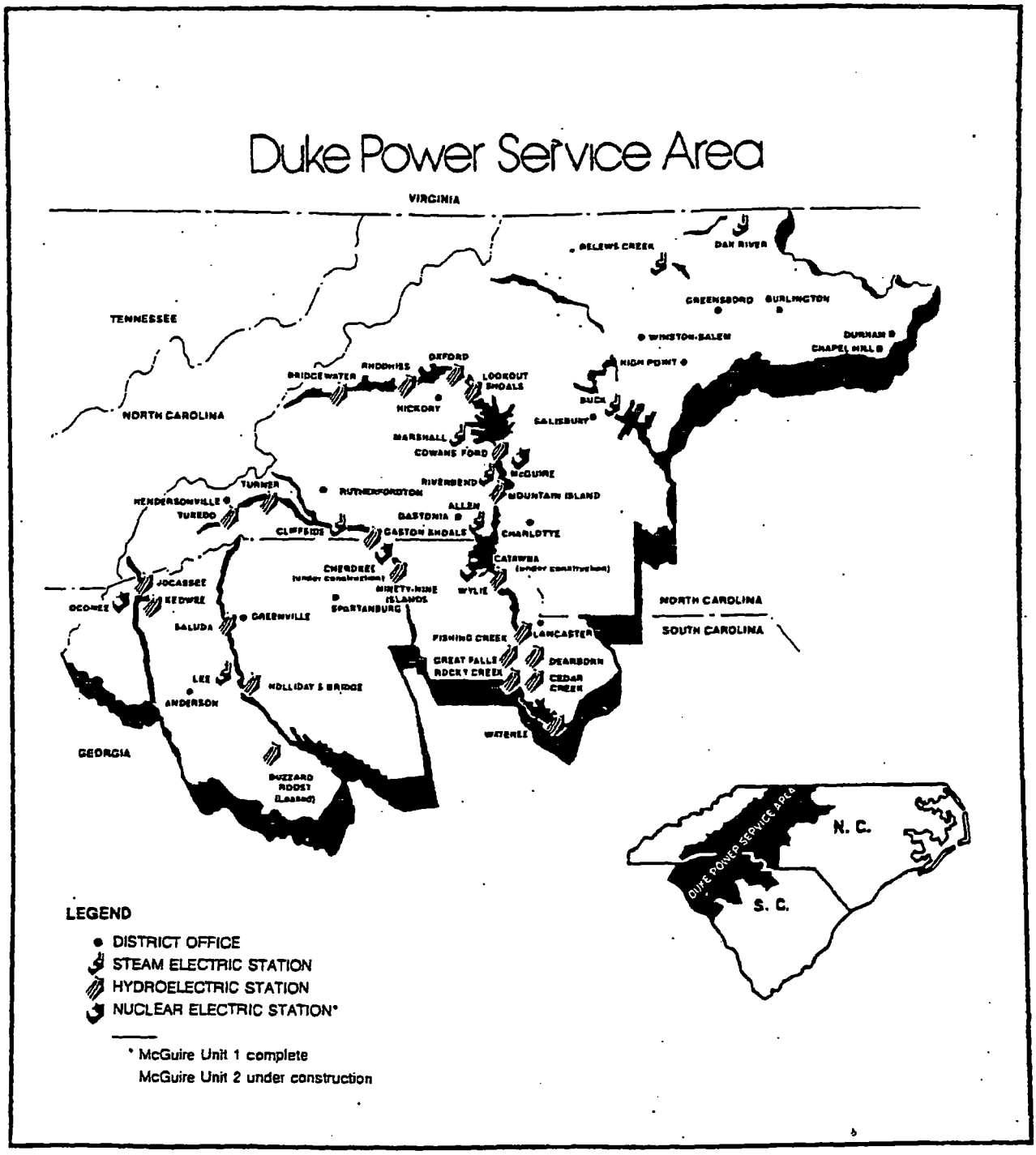
Duke Power Service Area
VIRGINIA
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
GEORGIA
BELEWS CREEK
DAN RIVER
GREENSBORO
BURLINGTON
WINSTON-SALEM
DURHAM
CHAPEL HILL
HIGH POINT
SALISBURY
BUCK
DEPOT
RHODHISS
BRIDGEWATER
LOOKOUT SHOALS
NICKORY
MARSHALL
COWANS FORD
RIVERBEND
McGUIRE
MOUNTAIN ISLAND
RUTHERFORDTON
ALLEN
GASTONIA
GASTON SHOALS
CHARLOTTE
CATAWBA
WYLIE
CLIFFSIDE
CHEROKEE
SPARTANBURG
TURNER
HENDERSONVILLE
TUXEDO
JOCASSEE
KEOWEE
OCONEE
SALUDA
GREENVILLE
FISHING CREEK
LANCASTER
GREAT FALLS
ROCKY CREEK
DEARBORN
CEDAR CREEK
WATEREE
LEE
ANDERSON
HOLLIDAY'S BRIDGE
BUZZARD ROOST
DUKE POWER SERVICE AREA
N. C.
S. C.
LEGEND
DISTRICT OFFICE
STEAM ELECTRIC STATION
HYDROELECTRIC STATION
NUCLEAR ELECTRIC STATION*
* McGuire Unit 1 complete
McGuire Unit 2 under construction

OPERATING STATISTICS

	Year Ended December 31				
	1982	1981	1980	1979	1978
Sources of Electric Energy					
Millions of kilowatt-hours:					
Generated—net output:					
Coal	38,927	42,513	40,984	37,404	34,589
Nuclear	15,009	14,229	14,213	14,228	15,905
Hydro	1,569	843	1,820	2,809	1,941
Oil and gas	7	146	203	163	484
Total generated	55,512	57,731	57,220	54,604	52,919
Net interchange and purchased power	(301)	494	(472)	(512)	1,016
Losses and company use	(3,831)	(4,677)	(4,437)	(3,769)	(3,996)
Total energy sales	51,380	53,548	52,311	50,323	49,939
Average Cost Per Ton of Coal Burned	$46.80	$43.24	$37.85	$35.86	$34.24
Electric Energy Sales					
Millions of kilowatt-hours:					
Residential	13,711	13,861	13,765	12,832	12,959
General service	10,087	9,731	9,395	8,778	8,920
Industrial					
Textile	9,215	10,101	10,152	10,394	10,446
Other	10,130	10,566	9,908	9,866	9,077
Wholesale and other energy sales	8,237	9,289	9,091	8,453	8,537
Total energy sales	51,380	53,548	52,311	50,323	49,939
Electric Revenues					
Thousands of dollars:					
Residential	$ 741,255	$ 624,986	$ 565,633	$ 499,936	$ 469,389
General service	485,064	386,141	340,691	303,858	284,752
Industrial					
Textile	335,727	293,081	263,024	254,877	233,277
Other	384,191	320,838	271,766	253,728	215,273
Wholesale and other energy sales	309,241	270,623	232,506	201,938	188,428
Other electric revenues	(10,998)	12,785	9,202	(21,780)	5,601
Total electric revenues	$2,244,480	$1,908,454	$1,682,822	$1,492,557	$1,396,720
Number of Customers—End of Year					
Residential	1,139,248	1,125,371	1,105,035	1,078,419	1,049,543
General service	168,897	167,282	165,522	161,833	159,538
Industrial					
Textile	1,302	1,313	1,324	1,326	1,303
Other	6,459	6,410	6,264	6,149	5,928
Wholesale and other energy sales	6,403	6,326	6,260	5,950	5,857
Total customers	1,322,309	1,306,702	1,284,405	1,253,677	1,222,169
Residential Customer Statistics					
Average number for year	1,136,431	1,118,534	1,095,933	1,068,194	1,039,275
Average annual use—KWH	12,065	12,392	12,560	12,013	12,469
Average annual billing	$652.27	$558.75	$516.12	$468.02	$451.65
Average Annual Billed Revenue Per KWH					
Residential	5.41¢	4.51¢	4.11¢	3.90¢	3.62¢
General service	4.81¢	3.97¢	3.63¢	3.46¢	3.19¢
Industrial	3.72¢	2.97¢	2.67¢	2.51¢	2.30¢
Wholesale and other energy sales	3.75¢	2.91¢	2.56¢	2.39¢	2.21¢

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age*
W. S. Lee**	Chairman of the Board and Chief Executive Officer	1982	53
D. W. Booth**	President and Chief Operating Officer, and Director	1982	58
W. H. Grigg**	Executive Vice President, Finance and Administration, and Director	1982	50
W. H. Owen**	Executive Vice President, Engineering and Construction, and Director	1982	56
A. C. Thies**	Executive Vice President, Power Operations, and Director	1982	61
Steve C. Griffith, Jr.**	Senior Vice President and General Counsel, and Director	1982	49
John D. Hicks**	Senior Vice President, Public Affairs, and Director	1977	59
Henry L. Cranford	Senior Vice President, Division Operations	1982	55
Donald H. Denton, Jr.	Senior Vice President, Marketing and Rates	1982	45
Frank A. Jenkins	Senior Vice President, Transmission and Distribution	1982	63
Thomas C. Berry	Vice President, Southern Division	1976	52
Ralph W. Bostian	Vice President, Production Support	1982	56
J. Kenneth Clark	Vice President, Corporate Communications	1981	50
L. C. Dail	Vice President, Design Engineering	1978	57
Robert L. Dick	Vice President, Construction	1971	55
George W. Ferguson, Jr.	Vice President and Deputy General Counsel	1982	50
M. T. Hatley, Jr.	Vice President, Rates	1979	60
E. N. Hedgepeth, Jr.	Vice President, Distribution	1982	55
S. T. Lattimore	Vice President, Finance Administration	1982	56
John F. Lomax	Vice President, Western Division	1980	43
Joe S. Major, Jr.	Vice President, Personnel	1971	62
Joseph G. Mann	Vice President, Northern Division	1973	59
Paul H. Mann, Jr.	Vice President, Operation	1978	60
Paul G. Martin	Vice President, Eastern Division	1982	50
Dwight B. Moore	Vice President, Central Division	1980	61
William O. Parker, Jr.	Vice President, Fossil Production	1982	58
E. Bruce Shuler	Vice President, Transmission	1982	55
William R. Stimart	Vice President, Regulatory Affairs	1979	51
George E. Stubbins	Vice President, Information Systems	1982	42
Hal B. Tucker	Vice President, Nuclear Production	1982	54
Fred E. West, Jr.	Vice President, Charlotte Division	1981	46
James W. White	Vice President, General Services	1979	57
Lewis F. Camp, Jr.	Secretary and Associate General Counsel	1980	54
Norman P. Morrow	Controller	1982	35
Richard J. Osborne	Treasurer	1981	32

* As of March 1983.
** Members of the Executive Committee.

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Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years except for J. Kenneth Clark and Norman P. Morrow. Mr. Clark served as Public Affairs Director of Mars, Inc., confectioner, from July 1978 to May 1981 when he joined the Company as Vice President, Corporate Communications. He served as Corporate News Bureau Director of Monsanto Company, a diversified chemical manufacturer, from 1976 to 1978. Mr. Morrow was an accountant with the firm of Deloitte Haskins & Sells from 1970 to 1980, when he joined the Company as Assistant Controller.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Item 2. ***Properties.***

The map on page 15 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V—Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see Item 1.—"Construction Program—Facilities Under Construction" and "Business—Fuel Supply".

Item 3. ***Legal Proceedings.***

Reference is made to Item 1.—"Construction Program" and "Business—Regulation" for information relating to licensing proceedings before the Nuclear Regulatory Commission with respect to the Company's nuclear generating facilities.

Reference is made to Item 1.—"Business—Rate Matters" regarding appeals taken from orders of the North Carolina Utilities Commission and an order of The Public Service Commission of South Carolina and pending proceedings before the North Carolina Utilities Commission and the Federal Energy Regulatory Commission.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of the Company's security holders during the last quarter of 1982.

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PART II.

Item 5. *Market for the Registrant's Common Equity and Related Stockholder Matters.*

The Common Stock of the Company is traded on the New York Stock Exchange. At February 18, 1983, there were approximately 122,000 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by *The Wall Street Journal* as composite transactions:

Common Stock	Dividends per Share	Price Range	
		High	Low
1982 by Quarter			
Fourth	$0.57	23½	20⅝
Third	0.57	23⅝	20½
Second	0.55	24	20⅜
First	0.55	23½	20⅜
1981 by Quarter			
Fourth	0.55	22½	19⅝
Third	0.51	21¼	18¾
Second	0.51	20⅛	17⅛
First	0.51	19¼	15⅞

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Item 6. *Selected Financial Data.*

DUKE POWER COMPANY

SELECTED FINANCIAL DATA

	Year Ended December 31				
	1982	1981	1980	1979	1978
	(Dollars in thousands, except per share figures)				
CONDENSED STATEMENTS OF INCOME					
Electric revenues	$2,244,480	$1,908,454	$1,682,822	$1,492,557	$1,396,720
Electric expenses	1,854,712	1,632,104	1,402,722	1,238,680	1,159,719
Electric operating income	389,768	276,350	280,100	253,877	237,001
Other income	175,048	254,043	208,365	168,612	131,899
Income before interest deductions	564,816	530,393	488,465	422,489	368,900
Interest deductions	214,939	194,142	177,374	147,729	138,299
Income before extraordinary item	349,877	336,251	311,091	274,760	230,601
Extraordinary item	48,304	—	—	—	—
Net income	398,181	336,251	311,091	274,760	230,601
Dividends on preferred and preference stocks	62,164	57,895	58,612	52,562	46,632
Earnings for common stock	$ 336,017	$ 278,356	$ 252,479	$ 222,198	$ 183,969
RATIO OF EARNINGS TO FIXED CHARGES (SEC method)	2.98	2.73	2.65	2.86	2.91
COMMON STOCK DATA					
Shares of common stock					
—End of year (thousands)	95,949	88,483	86,294	79,489	72,132
—Average (thousands)	93,679	87,313	81,985	77,168	70,367
Per share of common stock					
Earnings before extraordinary item	$ 3.07	$ 3.19	$ 3.08	$ 2.88	$ 2.61
Extraordinary item	0.52	—	—	—	—
Earnings	$ 3.59	$ 3.19	$ 3.08	$ 2.88	$ 2.61
Dividends	$ 2.24	$ 2.08	$ 1.95	$ 1.83	$ 1.74
Book value—end of year	$ 24.89	$ 23.83	$ 22.82	$ 22.12	$ 21.31
Market price—high-low	$ 24-20⅜	$ 22½-15⅞	$ 19¼-14⅛	$ 20⅝-16¼	$ 22-18⅛
—end of year	$ 23¼	$ 20⅜	$ 18⅛	$ 17¼	$ 19⅜
TOTAL ASSETS	$7,057,780	$6,531,044	$6,328,174	$5,615,372	$4,984,621
LONG-TERM DEBT	$2,712,372	$2,545,694	$2,594,008	$2,300,488	$1,974,209
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS	$ 304,026	$ 308,674	$ 316,559	$ 268,500	$ 220,000

See Notes to Financial Statements.

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Capital Needs

Since January 1, 1978, additions to property of $4.0 billion (including nuclear fuel) and retirements of $800 million have resulted in a net increase in gross plant of $3.2 billion. Retirements were unusually large because of sales of portions of the Catawba Nuclear Station in 1978 and 1981. During 1982 additions to property of $736 million (including nuclear fuel) and retirements of $82 million resulted in a net increase in gross plant of $654 million. Plant construction costs were lower in 1982 than in previous years because of the completion in late 1981 of Unit 1 of the McGuire Nuclear Station, prior sales of portions of the Catawba Nuclear Station, and recent curtailments in the construction program.

Projected construction and nuclear fuel costs are $2.5 billion for the years 1983 through 1985, excluding costs related to the portions of the Catawba Nuclear Station which have been sold. Construction plans reflect a decline in the projected growth rate of peak load. This decline is due in part to the Company's comprehensive load management program and energy conservation. The load management program is designed to limit future construction costs without restricting the continued economic development of the service area by encouraging consumers to reduce demands on the system.

The construction program includes plans for three nuclear units to begin operation within the next five years. Commercial operation of Unit 2 of the McGuire Nuclear Station is scheduled for early 1984. Total estimated costs, including nuclear fuel, for both units of the McGuire Station are $2.2 billion, including $2.0 billion spent as of December 31, 1982. The Company's portion of the total estimated construction and nuclear fuel costs for both units of the Catawba Nuclear Station is $1.0 billion, including $517 million spent as of December 31, 1982.

During the past two years, several planned generating units have been delayed or canceled. In 1982 Units 2 and 3 of the Cherokee Nuclear Station were canceled and the application for a construction permit for the proposed Perkins Nuclear Station was withdrawn. (See Note 12 in Notes to Financial Statements.) Completion of Unit 1 of the Cherokee Nuclear Station was indefinitely delayed in 1981. As of December 31, 1982, $538 million had been spent on this unit. Projected construction costs include nominal amounts for the Bad Creek Hydroelectric Station. As of December 31, 1982, $22 million had been spent on this pumped storage facility, although construction completion has not been definitely scheduled.

Expenditures for construction of major generating facilities and for nuclear fuel constituted approximately 80 percent of the Company's capital requirements during the past five years. Additional funds were required for transmission and distribution facilities, the refunding of maturing securities and sinking funds, and increased working capital.

Liquidity and Resources

The Company's long-term financial plan has three key goals: to improve the percentage of internal cash generation, to raise fixed charges coverage, and to strengthen capital structure. Achieving these goals should assist in attaining improved ratings on the Company's securities. The Company also seeks to sell common stock at or above book value. During the past five years, the market price of common stock has averaged 85 percent of book value.

The construction program currently requires expenditures greater than cash generated internally from operations. The Company initially funds the excess with short-term bank borrowings and commercial paper. While the Company prefers to limit short-term debt to about $150 million, it presently has bank lines of credit of $385 million. Short-term debt was $57 million as of December 31, 1982. The Company's policy is to refund short-term debt at least once each year, and such refundings have occurred in each of the past five years.

To supplement the internal generation of funds, the Company obtained an additional $781 million from the 1978 and 1981 sales of the Catawba Nuclear Station. Funds from the Catawba sale eliminated the need for external financing in 1981. Additional funds were obtained in the other years by issuing $1.2 billion in long-term debt (principally first and refunding mortgage bonds), $225 million in preferred stock, and $600 million in common stock, including the non-cash exchange for bonds in January 1982. (See Note 3 in Notes to Financial Statements.) To increase financing flexibility and to facilitate financing in the European market, Duke Power Overseas Finance N.V., a subsidiary in the Netherlands Antilles, was established. In April 1982, the net proceeds of a sale of $60 million principal amount of notes were borrowed from this subsidiary.

The Company's long-range objective is to generate at least 50 percent of its capital requirements from internal sources. From 1978 through 1982, funds from operations provided approximately 33 percent of the Company's capital requirements. In 1982, however, funds generated internally increased to 46 percent, mainly as a result of the inclusion of McGuire Unit 1 and additional construction work in progress (CWIP) in rate base.

During the past five years, the North Carolina Utilities Commission (NCUC) has granted rate increases allowing approximately 60 percent of the requested additional revenues. During 1982 legislation was enacted which could have a negative effect on the Company's ability to generate funds internally. This legislation revised the statutes under which the NCUC adjusts base rates to reflect fuel costs and under which the NCUC includes CWIP in rate base. In the Company's first rate order subsequent to this legislation, the NCUC allowed only 31 percent of the requested additional revenues to be implemented effective November 1, 1982; however, the amount of CWIP included in rate base was increased from $145 million to $276 million, which was almost 90 percent of the amount requested.

During the past five years, rate increases allowing approximately 60 percent of the requested additional revenues have been granted by The Public Service Commission of South Carolina. A January 1982 rate order allowed 55 percent of the requested additional revenues. On February 15, 1982, a request was filed for an additional increase in retail rates. An 11.5 percent increase, representing a portion of this request, was implemented subject to refund effective September 15, 1982. (See "Business—Rate Matters.")

The Company and its wholesale customers generally settle on rate increases based on the most recent NCUC rate order as it pertains to North Carolina retail industrial customers. A rate increase was implemented in November 1982, subject to refund and final approval by the Federal Energy Regulatory Commission.

To recover increasing costs and to include additional CWIP in rate base, a request for a 7.68 percent retail rate increase in North Carolina was filed in February 1983. Additional requests for increased rates are planned in the South Carolina and wholesale jurisdictions.

The Company seeks to maintain a capital structure containing no more than 47 percent debt and 40 to 42 percent common equity in order to improve financial strength. To improve capital structure while avoiding the dilution of shareholders' existing equity and to increase coverage ratios, 3,727,544 shares of common stock were issued in exchange for portions of several series of first and refunding mortgage bonds in January 1982. (See Note 3 in Notes to Financial Statements.) As of December 31, 1982, the capital structure was 47 percent long-term debt, 12 percent preferred stock, and 41 percent common equity.

The Company's goal for fixed charges coverage, using the Securities and Exchange Commission (SEC) method, is 3.5 times. During the past five years, actual coverage has not changed significantly because higher earnings have been offset by increasing embedded costs of debt. For the year 1982, this coverage was 2.98 times, but it is expected to improve as increased internal cash generation reduces external financing requirements.

The Company continually analyzes and implements alternative methods to meet its long-term financial goals. These methods have included cost reductions by means of a more stringent budgeting system and the adoption of an employee incentive plan for reducing costs. Unregulated business opportunities are being explored to enhance earnings. In addition, flexibility has been built into long-term construction plans to minimize financings under unfavorable conditions.

Results of Operations

Net Income and Dividends

From 1978 through 1982, earnings per share increased at an annual rate of 8 percent from $2.61 to $3.59. Earnings per share for 1982 includes a provision for loss of $.32 per share on the pending disposal of certain coal mining assets and an extraordinary gain of $.52 per share from the debt/equity exchange. (See Notes 1 and 3 in Notes to Financial Statements.) Although the earned return on common equity fluctuated during the past five years, the average earned return was consistently below the average return granted by the NCUC. During 1982 the Company's earned return was 13.9 percent, excluding the extraordinary item and the provision for loss on the disposal of assets. Dividends per share increased at an annual rate of 7 percent from $1.74 in 1978 to $2.24 in 1982.

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Revenues

Revenues increased at an annual rate of 13 percent over the 1978-1982 period because of increases in rates and kilowatt-hour sales. The rate increases were necessitated by the effects of inflation, the inclusion of construction work in progress and McGuire Unit 1 in rate base, and the increased cost of capital. Kilowatt-hour sales increased an average of 1 percent annually. This increase is principally attributable to a higher number of customers. Sales in 1982, however, were 4 percent lower than in 1981 because of milder weather conditions, a decline in the average kilowatt-hour usage per residential customer, and a decrease in industrial sales as a result of the current economic environment.

Operating Expenses

Increases in total electric expenses have substantially offset the increase in revenues during the 1978-1982 period. The most significant increase was in non-fuel operating and maintenence expense, which rose at an annual rate of 21 percent. Key factors were the commencement of commercial operation for McGuire Unit 1 on December 1, 1981, increased requirements by the Nuclear Regulatory Commission, and inflation. (See "Selected Financial Data—Effects of Changing Prices.") Fuel and purchased power expenses increased at an annual rate of 8 percent over the five-year period. In 1982, however, these expenses declined primarily because of reduced generation as a result of decreased kilowatt-hour sales.

Other

From 1978 through 1981, allowance for funds used during construction (ADC), included in both other income and interest deductions, increased as a result of higher construction work in progress and higher embedded costs of funds. In 1982, however, ADC decreased because McGuire Unit 1 began commercial operation on December 1, 1981, and additional construction work in progress was included in rate base. Interest income for 1981 was $20 million, which was unusually high because of the investment of proceeds from the Catawba sale. Earnings of subsidiaries amounted to $7 million in 1982. Since 1978 interest deductions and dividends on preferred and preference stocks have increased at annual rates of 12 percent and 7 percent, respectively. These increases are attributable to higher financing rates and the issuance of additional securities.

In anticipation of the disposition of the assets of Eastover Mining Company and the related land it leases from Eastover Land Company, a provision for loss of $30 million was recorded in 1982 (after the effect of income tax benefits of approximately $28 million). Both Eastover companies are wholly-owned subsidiaries. The Company determined to sell these properties after the most recent rate order from the NCUC prohibited full recovery of the cost of coal from these mines.

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Item 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company were prepared by management which is responsible for their integrity and objectivity. The statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions that should be included. The other information in the annual report is consistent with the financial statements. In preparing the financial statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. The Company's accounting controls provide reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected by employees within a timely period in the normal course of performing their assigned functions. The Company's accounting controls are continually reviewed for effectiveness and are augmented by written policies, standards and procedures, and a strong program of internal audit.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, composed solely of directors who are not officers or employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each and to monitor the discharge by each of their responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte Haskins & Sells, who have free access to the audit committee or the Board of Directors, without management present, to discuss internal accounting control, auditing and financial reporting matters.

AUDITORS' OPINION

DUKE POWER COMPANY:

We have examined the financial statements and supplemental schedules of Duke Power Company listed in the accompanying index on page 24. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 12, the Company has canceled plans for construction of two nuclear generating units and is requesting permission in each of its regulatory jurisdictions to recover all costs related to such units. The final outcome of this matter cannot presently be determined. In our report dated February 15, 1982, our opinion on the 1981 and 1980 financial statements referred to above was unqualified; however, in view of the uncertainty referred to above, our present opinion on such financial statements, as expressed herein, is different from that expressed in our previous report.

In our opinion, subject to the effects on the financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty referred to in the preceding paragraph been known, such financial statements present fairly the financial position of the Company at December 31, 1982 and 1981 and the results of its operations and the source of its funds for plant construction costs for each of the three years in the period ended December 31, 1982, in conformity with generally accepted accounting principles applied on a consistent basis. Also, in our opinion, the supplemental schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

Deloitte Haskins & Sells
DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 18, 1983

DUKE POWER COMPANY

STATEMENTS OF INCOME

	Year Ended December 31		
	1982	1981	1980
		(Dollars in thousands)	
ELECTRIC REVENUES (Notes 1 and 2)	$2,244,480	$1,908,454	$1,682,822
ELECTRIC EXPENSES			
Operation			
Fuel used in electric generation (Note 1)	781,406	790,967	680,693
Net interchange and purchased power (credit)	(10,685)	25,068	(12,908)
Wages, benefits and materials	329,954	264,488	211,014
Maintenance of plant facilities	177,766	131,670	114,597
Depreciation and amortization (Note 1)	186,080	142,899	131,441
General taxes	158,289	139,140	124,422
Income taxes (Notes 1 and 8)	231,902	137,872	153,463
Total electric expenses	1,854,712	1,632,104	1,402,722
Electric operating income	389,768	276,350	280,100
OTHER INCOME (Notes 1, 8 and 11)			
Allowance for equity funds used during construction	146,214	159,285	150,846
Earnings of subsidiaries, net	7,039	14,662	3,418
Provision for loss on disposal of assets	(30,000)	—	—
Other, net (deduction)	12,548	28,791	(3,299)
Income taxes—other, net (deduction)	(11,687)	(9,442)	(982)
Income taxes—credit	50,934	60,747	58,382
Total other income	175,048	254,043	208,365
Income before interest deductions	564,816	530,393	488,465
INTEREST DEDUCTIONS			
Interest on long-term debt	254,643	245,070	220,271
Other interest	12,802	11,694	17,287
Allowance for borrowed funds used during construction (credit) (Note 1)	(52,506)	(62,622)	(60,184)
Total interest deductions	214,939	194,142	177,374
Income before extraordinary item	349,877	336,251	311,091
EXTRAORDINARY ITEM (Note 3)	48,304	—	—
NET INCOME	398,181	336,251	311,091
Dividends on preferred and preference stocks	62,164	57,895	58,612
EARNINGS FOR COMMON STOCK	$ 336,017	$ 278,356	$ 252,479
COMMON STOCK DATA			
Average shares outstanding (thousands)	93,679	87,313	81,985
Earnings before extraordinary item	$3.07	$3.19	$3.08
Extraordinary item	0.52	—	—
Earnings per share	$3.59	$3.19	$3.08
Dividends per share	$2.24	$2.08	$1.95

See Notes to Financial Statements.

DUKE POWER COMPANY

STATEMENTS OF SOURCE OF FUNDS FOR PLANT CONSTRUCTION COSTS

	Year Ended December 31		
	1982	1981	1980
	(Dollars in thousands)		
FUNDS FROM OPERATIONS			
Income before non-fund extraordinary item	$349,877	$336,251	$311,091
Non-fund items			
Depreciation and amortization (includes nuclear fuel amortization)	268,651	224,675	210,600
Deferred income taxes and investment tax credit, net of amortization	159,515	109,572	68,198
Equity component of the allowance for funds used during construction	(146,214)	(159,285)	(150,846)
Other, net	25,171	(13,146)	2,989
Funds from operations	657,000	498,067	442,032
Dividends paid	(272,115)	(239,598)	(217,618)
Funds retained in the business	384,885	258,469	224,414
FUNDS FROM FINANCING AND SALE OF ASSETS—NET PROCEEDS			
First mortgage bonds	221,521	—	271,150
Common stock (Note 3)	199,134	35,954	105,829
Term notes	79,721	—	10,000
Preferred stock	38,296	—	49,323
Nuclear fuel trusts	33,052	42,248	30,664
Sale of an interest in the Catawba Nuclear Station (Note 11)	—	520,562	—
Increase (decrease) in notes payable for construction	(114,140)	(25,650)	85,000
Funds from financing and sale of assets	457,584	573,114	551,966
Total available funds	842,469	831,583	776,380
INCREASE IN WORKING CAPITAL REQUIREMENT	(58,068)	(92,946)	(31,000)
RETIREMENTS OF LONG-TERM DEBT AND PREFERRED STOCK (Note 3)	(194,555)	(93,551)	(43,211)
PLANT CONSTRUCTION EXPENDITURES	589,846	645,086	702,169
Equity component of the allowance for funds used during construction	146,214	159,285	150,846
PLANT CONSTRUCTION COSTS	$736,060	$804,371	$853,015
SUMMARY OF PLANT CONSTRUCTION COSTS			
Production	$405,329	$504,292	$590,420
Transmission	40,599	36,233	51,300
Distribution	113,881	112,073	92,990
General	23,895	22,557	25,000
Subtotal	583,704	675,155	759,710
Nuclear fuel	152,356	129,216	93,305
PLANT CONSTRUCTION COSTS	$736,060	$804,371	$853,015

See Notes to Financial Statements.

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DUKE POWER COMPANY

BALANCE SHEETS

ASSETS

	December 31	
	1982	1981
	(Dollars in thousands)	
ELECTRIC PLANT		
(At original cost—Notes 1, 7, 12 and 13)		
Electric plant in service	$5,940,941	$5,662,674
Less accumulated depreciation and amortization	2,106,427	1,842,831
Electric plant in service, net	3,834,514	3,819,843
Construction work in progress	2,551,177	2,178,464
Total electric plant, net	6,385,691	5,998,307
OTHER PROPERTY AND INVESTMENTS		
Other property—at cost (less accumulated depreciation: 1982—$7,384; 1981—$6,781)	28,675	26,444
Investments in and advances to subsidiaries (Note 1)	75,430	54,981
Other investments—at cost or less (Note 11)	24,900	22,592
Total other property and investments	129,005	104,017
CURRENT ASSETS		
Cash (Note 10)	4,053	4,526
Receivables (less allowance for losses: 1982—$3,983; 1981—$3,998)	162,671	189,036
Materials and supplies—at average cost		
Coal	179,987	126,581
Other	98,815	93,457
Prepayments	8,841	6,172
Total current assets	454,367	419,772
DEFERRED DEBITS		
Debt expense, being amortized over terms of related debt	4,961	3,113
Canceled construction projects (Note 12)	77,794	—
Other	5,962	5,835
Total deferred debits	88,717	8,948
TOTAL ASSETS	$7,057,780	$6,531,044

See Notes to Financial Statements.

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DUKE POWER COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31	
	1982	1981
	(Dollars in thousands)	
CAPITALIZATION		
(See Statements of Capitalization)		
Common stock equity	$2,388,592	$2,108,935
Preferred and preference stocks without sinking fund requirements	424,035	388,610
Preferred stocks with sinking fund requirements	304,026	308,674
Long-term debt	2,712,372	2,545,694
Total capitalization	5,829,025	5,351,913
CURRENT LIABILITIES		
Accounts payable	87,664	87,290
Interest accrued	85,453	71,615
Taxes accrued	61,037	59,958
Other	25,360	26,872
Total	259,514	245,735
Notes payable for construction—pending permanent financing (Note 10)	57,210	171,350
Current maturities of long-term debt and preferred stock	60,851	79,646
Total current liabilities	377,575	496,731
ACCUMULATED DEFERRED INCOME TAXES (Notes 1 and 8)	486,834	419,958
DEFERRED CREDITS		
Investment tax credit (Notes 1 and 8)	349,327	249,208
Other	15,019	13,234
Total deferred credits	364,346	262,442
COMMITMENTS AND CONTINGENCIES (Notes 12 and 13)		
TOTAL CAPITALIZATION AND LIABILITIES	$7,057,780	$6,531,044

See Notes to Financial Statements.

DUKE POWER COMPANY

STATEMENTS OF CAPITALIZATION AND RETAINED EARNINGS

CAPITALIZATION

	December 31	
	1982	1981
	(Dollars in thousands)	
COMMON STOCK EQUITY (Notes 3 and 4)		
Common stock, no par, 150,000,000 shares authorized; 95,948,783 and 88,482,596 shares outstanding for 1982 and 1981, respectively	$1,734,611	$1,579,093
Retained earnings	653,981	529,842
Total common stock equity	2,388,592	2,108,935
PREFERRED AND PREFERENCE STOCKS WITHOUT SINKING FUND REQUIREMENTS (Note 5)		
Preferred stock	415,000	375,000
Preference stock	9,035	13,610
Total preferred and preference stocks without sinking fund requirements	424,035	388,610
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS (Note 6)	304,026	308,674
LONG-TERM DEBT (Note 7)		
First and refunding mortgage bonds	2,474,598	2,376,250
Promissory note due subsidiary, 16½%—due 1989	58,725	—
Term note, floating rate—due 1987	21,000	—
Term note, 9.025%—due 1985	6,000	8,500
Pollution control obligations, 75% of prime rate—due 1983	2,500	2,500
Sinking fund debentures, 4⅛%—due 1982	—	25,000
Capitalized leases	96,738	101,579
Nuclear fuel trusts	125,000	125,000
Unamortized debt discount and premium, net	(15,338)	(15,489)
Current maturities of long-term debt	(56,851)	(77,646)
Total long-term debt	2,712,372	2,545,694
TOTAL CAPITALIZATION	$5,829,025	$5,351,913

RETAINED EARNINGS

	Year Ended December 31		
	1982	1981	1980
		(Dollars in thousands)	
BALANCE—Beginning of year	$529,842	$433,245	$343,225
ADD—Net income	398,181	336,251	311,091
Total	928,023	769,496	654,316
DEDUCT			
Dividends			
Common stock	210,206	181,703	159,240
Preferred and preference stocks	62,164	57,895	58,612
Capital stock expense	1,672	56	3,219
Total deductions	274,042	239,654	221,071
BALANCE—End of year	$653,981	$529,842	$433,245

See Notes to Financial Statements.

DUKE POWER COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

A. *Additions to Electric Plant.* The Company capitalizes all construction-related direct labor and materials, as well as indirect construction costs, including general engineering, taxes, and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized; the cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

B. *Allowance for Funds Used During Construction (ADC).* ADC is an accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are capitalized in the same manner as construction labor and material costs. ADC, a non-cash, non-operating item, is recognized as a cost of "Electric Plant" with offsetting credits to "Other Income" and "Interest Deductions." Under established regulatory rate practices, a utility is permitted to capitalize ADC with respect to construction work in progress (CWIP) not included in rate base, but is not permitted to do so with respect to CWIP included in rate base. After construction is completed, a utility is permitted to include a fair return on, and the recovery of, these capital costs through their inclusion in rate base and in the provision for depreciation. CWIP included in the Company's North Carolina rate base and excluded for purposes of capitalizing ADC was $276 million and $145 million at December 31, 1982 and 1981, respectively.

ADC, which is compounded semiannually, was calculated on average embedded rates (net of applicable income taxes) of 9.38 percent, 8.67 percent and 8.10 percent for 1982, 1981 and 1980, respectively.

C. *Depreciation and Amortization.* Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted average depreciation rates were 3.47 percent for 1982, 3.44 percent for 1981 and 3.33 percent for 1980. All coal-fired generating units are depreciated at the rate of 3.57 percent. Nuclear units are depreciated at a 4.00 percent rate, which includes an allowance for decommissioning costs.

Under the Nuclear Waste Policy Act of 1982, all electric utilities with nuclear facilities will be required to make payments to fund development and implementation of nuclear waste repositories. Provisions for amortization of nuclear fuel include estimates for disposal costs. Such provisions, which are included in "Fuel used in electric generation," are recorded using the unit-of-production method.

D. *Subsidiaries.* The Company accounts for investments in its subsidiaries, all of which are wholly-owned, using the equity method. Retained earnings include $47,709,738 of undistributed earnings of subsidiaries at December 31, 1982. Dividends received from subsidiaries were $1,600,000 in 1982, $981,302 in 1981 and $1,675,000 in 1980.

The Company intends to dispose of the assets of Eastover Mining Company and the related land leased from Eastover Land Company. In anticipation of this disposition, a provision for loss of $30 million was recorded in 1982 (after the effect of income tax benefits of approximately $28 million).

E. *Income Taxes.* The Company and its subsidiaries file a consolidated federal income tax return. Income taxes are allocated to each company based on its taxable income or loss.

Income taxes are allocated to electric operating expense and to non-electric operations under "Other Income." The "Income taxes—credit" classified under "Other Income" results from tax deductions of interest costs relating to investments in non-utility properties, mainly CWIP not included in rate base.

Deferred income taxes are provided for timing differences between book and tax income, principally resulting from accelerated tax depreciation, capitalized taxes and employee benefits, and nuclear fuel disposal costs. Investment tax credit is deferred and amortized over the useful lives of the related properties.

F. *Fuel Cost Adjustment Procedures.* The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel costs. In the South Carolina retail jurisdiction, fuel costs are reviewed semiannually with provisions for changing such costs in base rates. This jurisdiction allows the Company to reflect in revenues the difference between actual fuel costs incurred and fuel costs recovered through base rates. In the North Carolina retail jurisdiction, fuel costs in base rates are reviewed during general rate case proceedings. Also, an annual fuel hearing is required to review such costs in base rates. Procedures for the wholesale jurisdiction provide for monthly fuel cost adjustments.

2. Rate Matters

General rate increases since January 1, 1980 are as follows (dollars in thousands):

Jurisdiction and Date Implemented	Percent Increase	Annualized on 1982 Sales	Approximate Revenue Recorded Year Ended December 31		
			1982	1981	1980
N. C. Retail					
October 3, 1980	6.03	$ 66,100	$ 66,100	$ 66,700	$14,800
December 1, 1981	14.99	165,000	165,000	13,400	—
November 1, 1982	4.38	65,300	7,000	—	—
S. C. Retail					
December 1, 1981	13.00	55,000	55,000	21,600	—
September 15, 1982	11.50*	52,700	11,300	—	—
Wholesale					
October 3, 1980	6.71	13,500	13,500	13,700	3,300
January 23, 1981	2.10	4,500	4,500	4,100	—
December 1, 1981	11.86	29,400	29,400	2,700	—
November 2, 1982	10.16*	23,800	2,900	—	—
Total		$475,300	$354,700	$122,200	$18,100

* Subject to refund with interest.

3. Extraordinary Item

On January 7, 1982, the Company issued 3,727,544 shares of common stock with a market value of $73,489,000 in exchange for portions of several series of outstanding first and refunding mortgage bonds with a face value of $119,902,000. The transaction resulted in a non-taxable gain of $48,304,000, or $.52 per share, on the retirement of the bonds. The North Carolina Utilities Commission approved the classification of the transaction as an extraordinary item.

4. Common Stock and Retained Earnings

Common Stock

In 1982, 1981 and 1980, the Company received $199,134,000, $35,954,000 and $108,361,000 from the issuance of 7,274,724 shares, 1,884,944 shares and 6,278,820 shares of common stock, respectively. (See Note 3.)

At December 31, 1982, certain shares of common stock were reserved for issuance as follows:

	Shares
Stock Purchase-Savings Program for Employees	3,629,642
Conversion of Preference Stock	390,164
Dividend Reinvestment and Stock Purchase Plan	2,490,580
Employees' Stock Ownership Plan	1,998,738
Total	8,509,124

Retained Earnings

None of the Company's retained earnings as of December 31, 1982 were restricted with respect to the declaration or payment of dividends.

5. Preferred and Preference Stocks Without Sinking Fund Requirements

At December 31, 1982 and 1981, 10,000,000 shares of preferred stock ($100 par value) and 10,000,000 shares of preferred stock A ($25 par value) were authorized and issuable with or without sinking fund requirements. In addition, 1,500,000 shares of preference stock ($100 par value) were authorized at December 31, 1982 and 1981.

The outstanding Preference Stock, 6¾ percent Convertible Series AA, is convertible into shares of common stock at the adjusted conversion price of $23.89 per share, with each share of preference stock valued at $100 par for such purpose. The conversion price is subject to certain adjustments designed to protect the conversion privilege against dilution. In 1982, 1981 and 1980, 45,759 shares, 72,477 shares and 127,476 shares were converted into 191,463 shares, 303,236 shares and 526,657 shares of common stock, respectively.

Preferred and preference stocks without sinking fund requirements at December 31, 1982 and 1981 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1982	1981
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
8.70% F	1970	600,000	60,000	60,000
8.20% G	1971	600,000	60,000	60,000
7.80% H	1972	600,000	60,000	60,000
8.28% K	1977	500,000	50,000	50,000
8.84% M	1978	400,000	40,000	40,000
15.40% A	1982	1,600,000	40,000	—
6¾%, AA Convertible	1969	90,350	9,035	—
		136,109	—	13,610
Total			$424,035	$388,610

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6. Preferred Stocks With Sinking Fund Requirements

At December 31, 1982 and 1981, 10,000,000 shares of preferred stock ($100 par value) and 10,000,000 shares of preferred stock A ($25 par value) were authorized and issuable with or without sinking fund requirements.

Preferred stocks with sinking fund requirements at December 31, 1982 and 1981 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1982	1981
7.35 % I	1973	600,000	$ 60,000	$ 60,000
8.20 % J	1977	480,000	48,000	—
		500,000	—	50,000
8.375% L	1978	500,000	50,000	50,000
8.84 % N	1979	500,000	50,000	50,000
11.00 % O	1980	500,000	50,000	50,000
10.76 % A	1975	2,220,000	55,500	—
		2,280,000	—	57,000
		Shares Reacquired		
Less: Preferred shares reacquired for current and future sinking fund requirements—at cost				
10.76% A		83,998	(1,826)	—
		119,998	—	(2,660)
8.84% N		32,500	(2,419)	(2,430)
11.00% O		13,750	(1,229)	(1,236)
Less: Current sinking fund requirement				
8.20 % J			(2,000)	(2,000)
8.375% L			(2,000)	—
Total			$304,026	$308,674

The annual sinking fund requirements through 1987, net of amounts reacquired, are $4,000,000 in 1983, $7,300,050 in 1984, $7,900,000 in 1985, $9,525,000 in 1986 and $9,525,000 in 1987, with some additional redemptions permitted at the Company's option.

The call provisions for the outstanding preferred and preference stocks specify various redemption prices not exceeding 115 percent of par values plus accumulated dividends to the redemption date.

7. Long-Term Debt

First and refunding mortgage bonds outstanding at December 31, 1982 and 1981 were as follows (see Note 3) (dollars in thousands):

Series	Year Due	1982	1981	Series (continued)	Year Due	1982	1981
3⅜%	1986	$ 30,000	$ 30,000	7⅞%B	2001	$ 38,050	$ 40,000
14⅛%	1987	50,000	50,000	7¾%	2002	78,100	100,000
12%	1990	75,000	75,000	7⅜%B	2002	67,900	75,000
15⅛%	1991	100,000	—	7¾%	2003	94,872	100,000
4½%	1992	50,000	50,000	8⅛%B	2003	98,050	100,000
4¼%B	1992	50,000	50,000	9¾%	2004	95,623	100,000
11%	1994	84,500	91,250	9½%	2005	92,800	100,000
4½%	1995	40,000	40,000	8⅜%	2006	96,850	100,000
5⅛%	1997	72,600	75,000	8⅛%	2007	119,500	125,000
6⅛%	1998	68,500	75,000	9⅜%	2008	120,610	125,000
7%	1999	56,075	75,000	10⅛%	2009	145,050	150,000
8%B	1999	64,739	75,000	10⅞%B	2009	148,000	150,000
8½%	2000	69,244	75,000	14⅞%	2010	100,000	100,000
8¾%B	2000	95,635	100,000	13⅛%B	2010	50,000	50,000
7½%	2001	97,900	100,000	14½%	2012	125,000a	—
				Total		$2,474,598	$2,376,250

Substantially all electric plant was mortgaged at December 31, 1982.

The annual maturities of long-term debt (including sinking fund requirements and capitalized lease principal payments) through 1987 are $56,851,000 in 1983, $49,589,000 in 1984, $45,734,000 in 1985, $51,160,000 in 1986 and $81,727,000 in 1987.

Included in the annual maturities are amounts relating to $125,000,000 in outstanding obligations under two nuclear fuel trusts. Such maturities are based on estimated nuclear fuel consumption. The Company intends to transfer title of additional nuclear fuel to the trusts as fuel is consumed.

8. Income Tax Expense

Income tax expense consisted of the following (dollars in thousands):

	Year Ended December 31		
	1982	1981	1980
Electric Expenses			
Current income taxes			
Federal	$ 58,118	$ 30,244(a)	$ 69,134
State	21,694	11,183	16,121
	79,812	41,427	85,255
Deferred taxes, net			
Excess tax over book depreciation	46,985	49,353	25,114
Capitalized taxes, employee benefits, etc.	9,431	16,672	17,680
Revenues refundable	6,456	(8,281)	—
Repair allowance and cost of removal	(144)	(38)	5,872
Nuclear fuel disposal costs	(12,893)	(12,336)	(12,263)
	49,835	45,370	36,403
Investment tax credit			
Deferred	109,596	56,146	36,854
Amortization of deferments (credit)	(7,341)	(5,071)	(5,049)
	102,255	51,075	31,805
Total electric expenses	231,902	137,872	153,463
Other Income			
Income taxes—other, net (deduction)	11,687	51,592(b)	982
Income taxes—credit	(50,934)	(60,747)	(58,382)
Total other income	(39,247)	(9,155)	(57,400)
Total income tax expense	$192,655	$128,717	$ 96,063

(a) Reflects substantial investment tax credit utilization related to the tax gain on sale of assets in February 1981.

(b) Includes $42,150,000 resulting from the sale of assets in February 1981 and nominal amounts thereafter. (See Note 11.) Such income taxes, which are included in "Other, net (deduction)" on the Statements of Income, reflect a taxable gain in excess of book gain resulting principally from the treatment of ADC.

Total current income taxes were $33,128,000, $24,002,000 and $30,037,000 of which state income taxes were $15,687,000, $11,086,000 and $10,753,000 for 1982, 1981 and 1980, respectively.

Total deferred income taxes were $57,272,000, $53,641,000 and $34,221,000 of which deferred state income taxes were $7,430,000, $7,899,000 and $3,896,000 for 1982, 1981 and 1980, respectively.

Income taxes differ from amounts computed by applying the statutory tax rate to pretax income as follows (dollars in thousands):

	Year Ended December 31		
	1982	1981	1980
Income taxes on pretax income at the statutory federal rate of 46%	$263,365*	$213,885	$187,291
Increase (reduction) in tax resulting from:			
Allowance for all funds used during construction (ADC)	(91,411)	(102,077)	(97,074)
Amortization of electric investment tax credit deferrals	(7,341)	(5,071)	(5,049)
State income taxes, net of federal income tax benefit	12,132	13,595	9,044
Increase in tax expense primarily because of excess of tax gain over book profit on sale of assets	—	12,468	—
Other items, net	15,910	(4,083)	1,851
Total income tax expense (see above)	$192,655	$128,717	$ 96,063

* Pretax income excludes the provision for loss on disposition of assets of subsidiaries, recorded net of applicable income taxes. (See Note 1.)

9. Retirement Plan

The Company and two of its subsidiaries have a non-contributory, defined benefit retirement plan covering substantially all their employees. The Company's policy is to fund pension costs accrued. Total pension expense amounted to $32,000,000 in 1982, $31,896,000 in 1981 and $26,782,000 in 1980. Effective September 1, 1980 the plan was amended to provide for certain plan changes including increased benefits for active and retired employees. In 1981, the actuarial cost method and certain actuarial assumptions were changed. The effect of these changes did not significantly increase the Company's pension cost.

A comparison of accumulated plan benefits and plan net assets at December 31, 1981, the date of the latest actuarial report, and December 31, 1980 is as follows (dollars in thousands):

	1981	1980
Actuarial present value of accumulated plan benefits		
Vested	$229,783	$202,851
Non-Vested	71,742	60,332
Total	$301,525	$263,183
Net assets available for benefits	$263,241	$244,008

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 9.0 percent in 1981 and 8.3 percent in 1980.

10. Short-Term Borrowings

As of December 31, 1982, the Company had lines of credit with 72 commercial banks. These lines, plus the sale of commercial paper, were used to finance current cash requirements. The lines of credit were on either a fee basis and/or a compensating balance basis, with total balance requirements of $1,658,500.

Bank loans, normally for 90 days or less, are either at the lending bank's commercial prime interest rate or market rate. Certain of the Company's bank line arrangements may require additional balances related to usage.

A summary of short-term borrowings and credit arrangements is as follows (dollars in thousands):

	Year Ended December 31		
	1982	1981	1980
Amount outstanding at year-end—average rates of 10.38%, 11.69%, 17.74%, respectively	$ 57,210	$171,350	$197,000
Maximum amount outstanding during the year	$189,950	$250,398	$197,000
Average amount outstanding during the year	$ 74,148	$ 38,829	$ 84,466
Weighted average interest rate for the year—computed on a daily basis	12.38%	15.39%	12.91%
Lines of credit at year-end	$385,400	$305,400	$280,400

11. Other Income

In February 1981, the Company sold a 75 percent interest in Unit 1 of the Catawba Nuclear Station (Catawba) and a 37.5 percent interest in the station's support facilities to groups of North Carolina and South Carolina rural electric cooperative customers. At closing, $521 million and two notes totaling $76 million were received. The notes are non-interest bearing until 10 years after the first Catawba unit begins commercial operation, after which, interest and principal payments commence. The Company has discounted the notes and recorded the present value ($15.7 million and $13.8 million at December 31, 1982 and 1981, respectively) under "Other investments." The implicit interest on the notes is accrued monthly. At December 31, 1982 and 1981, "Construction work in progress" included $516,951,000 and $401,502,000, respectively, representing the Company's investment in its remaining interest in Catawba.

12. Canceled Construction Projects

The Board of Directors, at its February 23, 1982 meeting, approved the withdrawal of the Company's application for a construction permit for the proposed Perkins Nuclear Station. The Company has been permitted to recover the cost of Perkins allocated to its North Carolina retail jurisdiction over a five-year period beginning November 1, 1982. It is seeking similar recovery from the wholesale and South Carolina retail jurisdictions. Accordingly, the entire $8,927,000 cost of Perkins, excluding land, has been classified as a deferred debit and is being amortized to electric operations. As of December 31, 1982, the remaining unamortized balance was $8,630,000.

The Board of Directors, on November 2, 1982, announced the cancellation of Units 2 and 3 of the Cherokee Nuclear Station. Costs incurred related to Units 2 and 3 totaled $69,164,000 as of December 31, 1982. Significant costs relating to the cancellation will be incurred; however, the amount of such costs cannot be determined pending negotiations with suppliers. The Company is requesting permission in each of its regulatory jurisdictions to recover all costs related to these units.

13. Commitments and Contingencies

A. Construction Program

The Company is engaged in a construction program for which substantial commitments have been made. Projected construction and nuclear fuel costs are $1.93 billion and $581 million, respectively, for the years 1983 through 1985. The program is subject to periodic review and revision, and actual construction costs incurred may vary from such estimates. This is due to various factors including changing levels of inflation, revised load estimates, the cost and availability of capital, and the outcome of licensing and environmental matters.

On February 24, 1981, the Board of Directors, because of the uncertainty of the availability of funds on reasonable terms, indefinitely delayed completion of Unit 1 of the Cherokee Nuclear Station. This status remains unchanged. As of December 31, 1982, $538 million had been spent on this unit.

B. Nuclear Insurance

The Company's public liability for claims resulting from any nuclear incident is limited to $560 million under provisions of the Price-Anderson Act, which provides for nuclear liability insurance up to that amount. A portion of this insurance is provided through Nuclear Regulatory Commission regulations pursuant to which the Company could be assessed up to $5 million for each of its licensed reactors in the event there is a nuclear incident involving any licensed facility in the nation, with a maximum of $10 million a year for each of its licensed reactors in the event of more than one incident. At December 31, 1982, the Company had four licensed reactors.

Property damage coverage for certain of the Company's nuclear facilities is provided through membership in Nuclear Mutual Limited (NML). If NML's losses were to exceed its reserves, the Company could be liable, on a pro rata basis, for additional assessments of up to $86 million, representing 14 times the Company's current annual premium to NML.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), which provides insurance for the increased cost of generation and/or purchased power resulting from the accidental outage of a nuclear unit. If losses were to exceed the accumulated funds available to NEIL, the Company would be liable for a retrospective premium adjustment currently estimated to be $31 million, which is up to 5 times the regular annual premium.

The Company purchases from NEIL, through its Excess Property Insurance Program, $400 million of property damage insurance. This is in addition to the $500 million of coverage provided by the Company's underlying property damage policies issued through NML. If losses were to exceed the accumulated funds available to NEIL for the Excess Property Insurance Program, the Company would be liable for a retrospective premium adjustment of up to 7.5 times the regular annual premium. The maximum potential liability per incident currently is estimated to be $17 million.

SUPPLEMENTAL FINANCIAL DATA—(Unaudited)

Quarterly Financial Data

A summary of quarterly financial data for 1982 and 1981 is as follows (dollars in thousands except per share data):

	Electric Revenues	Electric Operating Income	Net Income	Earnings Per Share
1982 by Quarter				
Fourth	$540,925	$105,358	$ 71,127	$0.58
Third	578,902	97,144	97,702	0.87
Second	531,204	86,069	83,027	0.72
First	593,449	101,197	146,325	1.42
1981 by Quarter				
Fourth	$484,782	$ 64,388	$ 79,626	$0.74
Third	499,216	64,188	83,740	0.79
Second	426,200	70,397	80,111	0.76
First	498,256	77,377	92,774	0.90

Net income and earnings per share for the first quarter of 1982 include an extraordinary item of $48,304,000 or $0.52 per share. Net income and earnings per share for the fourth quarter of 1982 include a provision for loss on disposal of assets of $30,000,000 or $0.32 per share. Generally, quarterly earnings fluctuate with seasonal weather conditions, timing of rate increases (including fuel cost adjustment procedures) and maintenance of electric generating units, especially nuclear-fueled units.

See Notes to Financial Statements.

Effects of Changing Prices

In recent years, the impact of general inflation and changes in specific prices has caused distortions in traditional accounting measurements of income and capital. Although the rate of inflation in 1982 substantially decreased, the replacement of existing plant capacity occurs at a significantly higher cost than recovered through historical cost depreciation due to the high levels of inflation in previous years. In response to this problem, the Financial Accounting Standards Board (FASB) issued Statement No. 33 requiring disclosure of the effects of inflation on a company's operations and financial position.

Because the accompanying supplementary information involves various assumptions and approximations, it should be viewed as an estimate of the effects of inflation, rather than a precise measurement.

Constant Dollar Accounting

Constant dollar accounting reflects the overall decline in the purchasing power of the dollar by restating historical costs in terms of dollars of equal purchasing power.

Constant dollar amounts for electric plant in service were determined by indexing surviving historical costs of plant with the Consumer Price Index for all Urban Consumers (CPI-U). Historical depreciation rates were applied to the restated amounts of plant thereby trending the provision for depreciation to reflect the impact of general inflation.

Current Cost Accounting

Current cost accounting reflects changes in specific prices of the property used in the Company's operations from the date the property was acquired to the present. This method differs from constant dollar accounting to the extent that costs of specific utility property have increased more or less rapidly than the rate of general inflation. The current cost amounts of plant in service represent the estimated cost for replacing existing plant facilities and were determined by indexing surviving plant costs by internally generated indices or the Handy-Whitman Index of Public Utility Construction Costs. Since plant facilities are not expected to be replaced precisely in kind, "current cost" does not necessarily represent the replacement cost of existing productive capacity. Current cost depreciation is computed by applying the same rates used in the historical cost and constant dollar statements to the current cost plant amounts.

Effects of Rate Regulation

Under the Company's present ratemaking procedures, only the historical cost of plant in service is recoverable in rates as depreciation. Therefore, the excess of the cost of plant stated in terms of constant dollars or current costs over the historical cost of plant, resulting from inflation in the current year, is not presently recoverable in rates as depreciation, and is reflected as a reduction to net recoverable cost.

The reduction is offset by the Company having significant amounts of long-term debt outstanding, as well as other net monetary liabilities, which will be paid back in dollars of less purchasing power. Thus, the gain from decline in purchasing power of net amounts owed in the accompanying schedules results from inflation's effect on obligations to pay cash at a future date.

Other

Income statement items other than depreciation have not been adjusted. The Company's operation and maintenance expenses already include the average effects of changing prices during the period and, therefore, no adjustments have been made to them.

No adjustments to income tax expense have been made in computing the impact of inflation since only historical costs are deductible for income tax purposes.

Supplementary Statement of Earnings for Common Stock Adjusted for Changing Prices

	Year Ended December 31, 1982		
	Historical $	Constant Dollar	Current Cost
		(Dollars in thousands)	
Electric revenues	$2,244,480	$2,244,480	$2,244,480
Operating expenses	1,100,675	1,100,675	1,100,675
Maintenance of plant facilities	177,766	177,766	177,766
Depreciation	186,080	392,536	410,277
Taxes	390,191	390,191	390,191
Total operating expenses	1,854,712	2,061,168	2,078,909
Operating income	389,768	183,312	165,571
Other income	175,048	175,048	175,048
Income before interest	564,816	358,360	340,619
Interest expense	214,939	214,939	214,939
Income before extraordinary item	349,877	143,421	125,680
Extraordinary item	48,304	48,304	48,304
Net income	398,181	191,725	173,984
Dividends on preferred and preference stocks	62,164	62,164	62,164
Earnings for common stock	$ 336,017	$ 129,561*	$ 111,820
Increase in specific prices (current cost) of utility plant held during the year**			$ 287,288
Reduction to net recoverable cost		$ (9,078)	
Effect of increase in general price level			(386,771)
Excess of increase in general price level over increase in specific prices			(99,483)
Gain from decline in purchasing power of net amounts owed		146,148	146,148
Net		$ 137,070	$ 46,665

* If the reduction to net recoverable cost of $9,078,000 were reflected, and no recognition were given to the $146,148,000 purchasing power gain, earnings for common stock on a constant dollar basis would have been $120,483,000.

** At December 31, 1982, current cost of electric plant, net of accumulated depreciation, was $10,419,359,000.

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

	1982	1981	1980	1979	1978
	(In thousands of average 1982 dollars, except per share figures)				
Electric revenues					
In historical dollars	$2,244,480	$1,908,454	$1,682,822	$1,492,557	$1,396,720
In constant dollars	2,244,480	2,025,455	1,971,247	1,984,812	2,066,488
Income from continuing operations					
In historical dollars	349,877	336,251	311,091	274,760	
In constant dollars	143,421	175,087	197,199	216,211	
In current cost	125,680	153,604	177,474	188,889	
Earnings per share before extraordinary item					
In historical dollars	3.07	3.19	3.08	2.88	
In constant dollars	.86	1.31	1.57	1.90	
In current cost	.67	1.05	1.33	1.54	
Common stock dividends per share					
In historical dollars	2.24	2.08	1.95	1.83	1.74
In constant dollars	2.24	2.21	2.28	2.43	2.57
Market price per common share at year-end					
In historical dollars	23.25	20.625	18.125	17.25	19.375
In constant dollars	22.99	21.18	20.28	21.69	27.61
Net assets at year-end					
In historical dollars	2,388,592	2,108,935	1,969,140	1,758,016	
In constant dollars	2,361,635	2,165,872	2,203,090	2,210,711	
In current cost	2,361,635	2,165,872	2,203,090	2,210,711	
Purchasing power gain on net monetary items	146,148	346,958	482,925	514,678	
Decrease in the current cost of electric plant in service, net of inflation, after reduction to net recoverable cost	99,483	280,634	524,346	584,586	
Average Consumer Price Index	289.1	272.4	246.8	217.4	195.4

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DUKE POWER COMPANY

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Balance Beginning of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1982					
Electric Plant in Service—At Original Cost					
Production	$2,829,823	$ 23,647	$ 340	$ 161	$2,853,291
Transmission	850,499	51,580	1,928	3,226	903,377
Distribution	1,360,583	114,484	11,887	1,322	1,464,502
General	230,432	23,280	4,920	601	249,393
Miscellaneous	16,923	3,919	—	(35)	20,807
Nuclear Fuel	374,414	75,343	—	(186)	449,571
Total electric plant in service	5,662,674	292,253	19,075	5,089	5,940,941
Construction Work in Progress	2,178,464	440,976	—	(68,263)(1)	2,551,177
Other Property—At Cost					
Water plant	23,711	2,860	—	4	26,575
Transit plant	2,974	—	—	—	2,974
Non-utility plant	6,540	(29)	38	37	6,510
Total other property	33,225	2,831	38	41	36,059
Total plant	$7,874,363	$ 736,060	$19,113	$ (63,133)	$8,528,177
For the Year Ended December 31, 1981					
Electric Plant in Service—At Original Cost					
Production	$1,902,374	$ 927,983(2)	$ 1,058	$ 524	$2,829,823
Transmission	794,988	57,769	1,833	(425)	850,499
Distribution	1,262,939	105,714	11,700	3,630	1,360,583
General	207,821	18,898	5,412	9,125	230,432
Miscellaneous	15,622	1,301	—	—	16,923
Nuclear Fuel	235,408	138,820	—	186	374,414
Total electric plant in service	4,419,152	1,250,485	20,003	13,040(3)	5,662,674
Construction Work in Progress	3,114,807	(450,604)(2)	—	(485,739)(4)	2,178,464
Other Property—At Cost					
Water plant	18,600	5,151	—	(40)	23,711
Transit plant	525	666	—	1,783	2,974
Non-utility plant	7,873	(1,327)	1,077	1,071	6,540
Total other property	26,998	4,490	1,077	2,814(3)	33,225
Total plant	$7,560,957	$ 804,371	$21,080	$(469,885)	$7,874,363
For the Year Ended December 31, 1980					
Electric Plant in Service—At Original Cost					
Production	$1,826,359	$ 14,438	$ 635	$ 62,212	$1,902,374
Transmission	771,644	24,531	1,496	309	794,988
Distribution	1,178,994	90,271	10,993	4,667	1,262,939
General	169,519	19,338	3,842	22,806	207,821
Miscellaneous	10,445	5,177	—	—	15,622
Nuclear fuel	169,552	65,856	—	—	235,408
Total electric plant in service	4,126,513	219,611	16,966	89,994	4,419,152
Construction Work in Progress	2,481,957	632,850	—	—	3,114,807
Other Property—At Cost					
Water plant	18,187	1,494	1,040	(41)	18,600
Transit plant	525	—	—	—	525
Non-utility plant	8,771	(940)	446	488	7,873
Total other property	27,483	554	1,486	447	26,998
Total plant	$6,635,953	$ 853,015	$18,452	$ 90,441(5)	$7,560,957

(1) Principally due to the cancellation of Units 2 and 3 of the Cherokee Nuclear Station and the Perkins Nuclear Station.

(2) Principally due to Unit 1 of McGuire Nuclear Station commencing commercial operation on December 1, 1981.

(3) Principally due to the purchase of transportation equipment previously leased.

(4) Represents the book value of a portion of the Catawba Nuclear Station sold in February 1981.

(5) Principally due to capitalization of leases at December 31, 1980.

DUKE POWER COMPANY

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Beginning of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1982						
Accumulated Depreciation of Electric Plant						
Production	$ 765,425	$103,315	$ —	$ 349	$ —	$ 868,391
Transmission	254,450	24,802	—	557	300	278,995
Distribution	448,680	47,683	—	8,982	(236)	487,145
General	81,668	6,180	7,948	4,096	(64)	91,636
Miscellaneous	3,140	—	519	—	—	3,659
	1,553,363	181,980	8,467	13,984	—	1,729,826
Accumulated Amortization of Limited Term Plant	179	—	300	—	—	479
Accumulated Amortization of Nuclear Fuel	289,289	—	86,833	—	—	376,122
	1,842,831	181,980	95,600	13,984	—	2,106,427
Accumulated Depreciation of Water Plant	4,648	387	—	(4)	—	5,039
Accumulated Depreciation of Transit Plant	2,133	212	—	—	—	2,345
Total Accumulated Depreciation	$1,849,612	$182,579	$95,600	$13,980	$ —	$2,113,811
For the Year Ended December 31, 1981						
Accumulated Depreciation of Electric Plant						
Production	$ 699,674	$ 66,907	$ —	$ 1,156	$ —	$ 765,425
Transmission	233,096	23,037	—	1,749	66	254,450
Distribution	412,312	44,434	—	8,000	(66)	448,680
General	64,837	4,921	7,977	3,185	7,118	81,668
Miscellaneous	2,621	—	519	—	—	3,140
	1,412,540	139,299	8,496	14,090	7,118	1,553,363
Accumulated Amortization of Limited Term Plant	75	—	104	—	—	179
Accumulated Amortization of Nuclear Fuel	216,494	—	72,795	—	—	289,289
	1,629,109	139,299	81,395	14,090	7,118	1,842,831
Accumulated Depreciation of Water Plant	4,326	360	—	38	—	4,648
Accumulated Depreciation of Transit Plant	225	125	—	—	1,783	2,133
Total Accumulated Depreciation	$1,633,660	$139,784	$81,395	$14,128	$ 8,901(1)	$1,849,612
For the Year Ended December 31, 1980						
Accumulated Depreciation of Electric Plant						
Production	$ 606,945	$ 61,722	$ —	$ 982	$31,989	$ 699,674
Transmission	211,361	22,228	—	167	(326)	233,096
Distribution	378,134	41,181	—	7,329	326	412,312
General	55,062	4,268	7,179	2,063	391	64,837
Miscellaneous	2,102	—	519	—	—	2,621
	1,253,604	129,399	7,698	10,541	32,380	1,412,540
Accumulated Amortization of Limited Term Plant	19	—	56	—	—	75
Accumulated Amortization of Nuclear Fuel	145,409	—	71,085	—	—	216,494
	1,399,032	129,399	78,839	10,541	32,380	1,629,109
Accumulated Depreciation of Water Plant	5,027	339	—	1,040	—	4,326
Accumulated Depreciation of Transit Plant	189	36	—	—	—	225
Total Accumulated Depreciation	$1,404,248	$129,774	$78,839	$11,581	$32,380(2)	$1,633,660

(1) Principally due to the purchase of transportation equipment previously leased.
(2) Principally due to capitalization of leases at December 31, 1980.

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DUKE POWER COMPANY

SCHEDULE VIII—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(Dollars in thousands)

Description	Balance Beginning of Year	Charged To Costs and Expenses	Deductions	Balance End of Year
For the Year Ended December 31, 1982				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 3,998	$5,254	$5,269(1)	$ 3,983
Other Reserves				
Operating Reserves(3)	$12,269	$3,374	$1,712(2)	$13,931
For the Year Ended December 31, 1981				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 4,064	$4,184	$4,250(1)	$ 3,998
Other Reserves				
Operating Reserves(3)	$11,085	$3,243	$2,059(2)	$12,269
For the Year Ended December 31, 1980				
Reserves Deducted from Assets on Balance Sheet				
Provision for Uncollectible Accounts	$ 4,131	$3,402	$3,469(1)	$ 4,064
Other Reserves				
Operating Reserves(3)	$ 9,531	$3,266	$1,712(2)	$11,085

(1) Uncollectible accounts written off, net of recoveries.

(2) Entries represent payments primarily for injuries and damages in North Carolina and South Carolina.

(3) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits," on the Balance Sheets.

SCHEDULE X—SUPPLEMENTARY INCOME STATEMENT INFORMATION

	Year Ended December 31		
	1982	1981	1980
	(Dollars in thousands)		
Taxes, other than payroll and income taxes:			
Real and personal property	$ 32,746	$ 34,292	$ 32,783
State and city franchise	101,913	85,296	75,264
Other	6,543	6,399	6,208
Total	$141,202	$125,987	$114,255

EXHIBIT I

DUKE POWER COMPANY

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE—(Unaudited)

This calculation is submitted in accordance with Release No. 9083 under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	Year Ended December 31		
	1982	1981	1980
	(Dollars in thousands except per share figures)		
Fully Diluted:			
Earnings applicable to common stock(1)	$336,017(3)	$278,356	$252,479
Add: Dividends on Preference Stock, 6¾% Convertible Series AA	747	1,158	1,919
Earnings as adjusted for computation	$336,764	$279,514	$254,398
Average common shares outstanding—twelve months (thousands)	93,679	87,313	81,985
Add: Common shares required for conversion of Preference Stock, 6¾% Convertible Series AA, $100 par, 500,000 shares authorized (90,350 shares outstanding as of December 31, 1982)(2)	378	570	873
Common shares as adjusted for computation	94,057	87,883	82,858
Fully diluted earnings per share	$3.58	$3.18	$3.07

(1) These figures agree with the related amounts in the Statements of Income.

(2) The conversion price used to convert the Preference Stock, 6¾% Convertible Series AA, into shares of common stock was $23.89.

(3) Earnings applicable to common stock includes an extraordinary item of $48,304,000, or $0.52 per share.

Item 9. *Disagreements on Accounting and Financial Disclosure.*

No events necessary to be disclosed by the Company under this item have occurred.

PART III.

Item 10. *Directors and Executive Officers of the Registrant.*

Information for this item concerning directors of the Company is set forth in the section entitled "Election of Directors" in the proxy statement of the Company relating to its 1983 annual meeting of shareholders, which is incorporated herein by reference.

Information concerning the executive officers of the Company is set forth on page 17 of this annual report.

Item 11. *Management Remuneration.*

Information for this item is set forth in the section entitled "Remuneration of Directors and Officers" in the proxy statement of the Company relating to its 1983 annual meeting of shareholders, which is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management.*

Information for this item is set forth in the sections entitled "Voting Securities Outstanding" and "Security Ownership of Management" in the proxy statement of the Company relating to its 1983 annual meeting of shareholders, which is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions.*

Information for this item is set forth in the section entitled "Election of Directors" in the proxy statement of the Company relating to its 1983 annual meeting of shareholders, which is incorporated herein by reference.

PART IV.

Item 14. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K.*

Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

- Financial Statements
  - Statements of Income for the Three Years Ended December 31, 1982
  - Statements of Source of Funds for Plant Construction Costs for the Three Years Ended December 31, 1982
  - Balance Sheets—December 31, 1982 and 1981
  - Statements of Capitalization—December 31, 1982 and 1981
  - Statements of Retained Earnings for the Three Years Ended December 31, 1982
  - Notes to Financial Statements
- Supplemental Financial Data (Unaudited)
- Supplemental Schedules
  - Schedule V—Property, Plant and Equipment for the Years Ended December 31, 1982, 1981 and 1980
  - Schedule VI—Accumulated Depreciation and Amortization of Property, Plant and Equipment for the Years Ended December 31, 1982, 1981 and 1980
  - Schedule VIII—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 1982, 1981 and 1980
  - Schedule X—Supplementary Income Statement Information for the Years Ended December 31, 1982, 1981 and 1980

Exhibit I—Computation of Fully Diluted Earnings Per Share (Unaudited)

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

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Financial statements and schedules of the Company's subsidiaries are omitted because all such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Exhibits

(a) —See Exhibit Index on page 49.

(b) —Annual Report on Form 11-K with respect to the Stock Purchase-Savings Program for Employees of the Company for the fiscal year ended October 31, 1982 and the Employees' Stock Ownership Plan for the year ended December 31, 1982.

Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1982.

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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 in the City of Charlotte and State of North Carolina on the 30th day of March, 1983.

DUKE POWER COMPANY
(Registrant)

By: W. S. LEE
Chairman of the Board

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
W. S. LEE	Chairman of the Board (Principal Executive Officer)	March 30, 1983
W. H. GRIGG	Executive Vice President, Finance and Administration (Principal Financial Officer)	March 30, 1983
NORMAN P. MORROW	Controller (Principal Accounting Officer)	March 30, 1983
NAOMI G. ALBANESE D. W. BOOTH THOMAS H. DAVIS ROBERT C. EDWARDS JOHN L. FRALEY ALESTER G. FURMAN III STEVE C. GRIFFITH, JR. W. H. GRIGG GEORGE R. HERBERT JOHN D. HICKS JAMES V. JOHNSON W. S. LEE BUCK MICKEL REECE A. OVERCASH, JR. WARREN H. OWEN JAMES C. SELF MACEO A. SLOAN A. C. THIES WILLIAM L. WATKINS	A majority of the Directors	March 30, 1983

LEWIS F. CAMP, JR., by signing his name hereto, does hereby sign this document on behalf of the issuer and on behalf of each of the above-named persons pursuant to powers of attorney duly executed by the issuer and such persons, filed with the Securities and Exchange Commission as supplemental information.

Lewis F. Camp, Jr., Attorney-in-fact

EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit Number	
3-A	—Restated Charter of registrant, dated as of January 1, 1979 (filed with Form S-7, File No. 2-63592, effective March 14, 1979, as Exhibit 2-B-1).
3-B	—Articles of Amendment to the Articles of Incorporation dated May 4, 1981 (filed with Form 10-K for the year ended December 31, 1981, File No. 1-4928, as Exhibit 3-B).
3-C	—Statement of Classification of Shares relating to the 8.84% Cumulative Preferred Stock, Series N (filed with Form S-16, File No. 2-66561, effective February 6, 1980, as Exhibit 2-B-3).
3-D	—Statement of Classification of Shares relating to the 11% Cumulative Preferred Stock, Series O (filed with Form S-16, File No. 2-68582, effective August 19, 1980, as Exhibit 2-B-3).
3-E	—Statement of Classification of Shares relating to the 15.40% Preferred Stock A, 1982 Series (filed with Form S-16, File No. 2-75953, effective February 23, 1982, as Exhibit 2-B-5).
3-F	—By-Laws of registrant, as amended to date (filed with Form 10-K for the year ended December 31, 1981, File No. 1-4928, as Exhibit 3-F).
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-3	—Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).
4-B-4	—Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12	—Supplemental Indenture, dated as of April 1, 1951, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13	—Supplemental Indenture, dated as of September 1, 1953, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-15	—Supplemental Indenture, dated as of January 1, 1955, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).
4-B-16	—Supplemental Indenture, dated as of May 1, 1956, supplementing said Mortgage (filed with Form S-9, File No. 2-12402, effective April 26, 1956, as Exhibit 2-B-16).

Exhibit Number	
4-B-17	—Supplemental Indenture, dated as of January 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).
4-B-18	—Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-19	—Supplemental Indenture, dated as of February 1, 1962, supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).
4-B-20	—Supplemental Indenture, dated as of August 1, 1962, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).
4-B-21	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-20).
4-B-22	—Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).
4-B-23	—Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15,1968, as Exhibit 2-B-25).
4-B-24	—Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).
4-B-25	—Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).
4-B-26	—Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).
4-B-27	—Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).
4-B-28	—Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).
4-B-29	—Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).
4-B-30	—Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effective March 7, 1972, as Exhibit 2-B-30).
4-B-31	—Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).
4-B-32	—Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).
4-B-33	—Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).
4-B-34	—Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).
4-B-35	—Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).
4-B-36	—Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).
4-B-37	—Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).
4-B-38	—Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).
4-B-39	—Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).
4-B-40	—Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).
4-B-41	—Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).

Exhibit Number	
4-B-42	—Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).
4-B-43	—Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-68571, effective August 19, 1980, as Exhibit 2-B-43).
4-B-44	—Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).
4-B-45	—Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).
4-B-46	—Supplemental Indenture, dated as of September 1, 1982, supplementing said Mortgage (filed with Form S-3, File No. 2-78882, effective August 30, 1982, as Exhibit 4-B-46).
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated as of August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated as of October 14, 1980, between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated as of October 14, 1980, between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
*12	—Computation of Ratio of Earnings to Fixed Charges.
*24	—Consent of Independent Auditors.

EXHIBIT 24

CONSENT OF INDEPENDENT AUDITORS

Duke Power Company:

We hereby consent to the incorporation by reference in Registration Statements No. 2-78883, No. 2-79057 and No. 2-81066 on Form S-3 and in Post-Effective Amendment No. 1 to Registration Statement No. 2-72172 on Form S-8 of our opinion, dated February 18, 1983, appearing in this annual report on Form 10-K of Duke Power Company for the year ended December 31, 1982.

Deloitte Haskins & Sells
DELOITTE HASKINS & SELLS

Charlotte, North Carolina
March 30, 1983

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EXHIBIT 12

DUKE POWER COMPANY

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in Thousands)

	Year Ended December 31				
	1978(1)	1979(1)	1980(1)	1981(1)	1982
Income from continuing operations before provision for income taxes	$345,706	$366,839	$405,411	$451,288	$546,465(2)
Fixed charges	181,437	196,828	245,718	261,319	276,162(3)
Total	$527,143	$563,667	$651,129	$712,607	$822,627
Fixed charges					
Interest on long-term debt	$164,998	$178,530	$219,416	$244,118	$253,577
Interest on short-term loans	4,160	4,386	11,464	6,150	8,673
Other interest	2,373	5,366	5,823	5,544	9,020(3)
Amortization of debt discount, premium and expense	928	833	855	952	1,066
Interest component of rentals	8,978	7,713	8,160	4,555	3,826
Fixed charges	$181,437	$196,828	$245,718	$261,319	$276,162
Ratio of earnings to fixed charges	2.91	2.86	2.65	2.73	2.98

NOTES:

(1) These amounts have not been restated to reflect subsidiary earnings and fixed charges as the effects would not be material. Earnings before income taxes thus exclude undistributed earnings of subsidiaries of $6,559,000 for 1978, $4,647,000 for 1979, $1,743,000 for 1980 and $13,681,000 for 1981.

(2) Includes earnings before income taxes of subsidiaries of $10,972,000.

(3) Includes adjustment of $4,890,000 for fixed charges of subsidiaries, net of intercompany transactions.

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WARNING
FOR ARCHIVES
Do Not Damage Or Destroy

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1983 — Commission File Number: 1-4928

Duke Power Company

(Exact name of registrant as specified in its charter)

North Carolina	56-0205520
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
422 South Church Street, Charlotte, North Carolina	28242
(Address of principal executive offices)	(Zip Code)

704-373-4011

(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
Preferred Stock, par value $100	
3.70% Series F	New York Stock Exchange
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
8.84% Series M	New York Stock Exchange
8.84% Series N	New York Stock Exchange
11% Series O	New York Stock Exchange
Preferred Stock A, par value $25	
10.76% Series 1975	New York Stock Exchange
15.40% Series 1982	New York Stock Exchange
Preference Stock, par value $100	
6¾% Convertible Series AA	New York Stock Exchange
First and Refunding Mortgage Bonds	
7⅞% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7⅞% Series B Due 2002	New York Stock Exchange
7¾% Series Due 2003	New York Stock Exchange
8⅛% Series B Due 2003	New York Stock Exchange
9¾% Series Due 2004	New York Stock Exchange
9½% Series Due 2005	New York Stock Exchange
8⅜% Series Due 2006	New York Stock Exchange
8⅛% Series Due 2007	New York Stock Exchange
9⅜% Series Due 2008	New York Stock Exchange
10⅛% Series Due 2009	New York Stock Exchange
10⅞% Series B Due 2009	New York Stock Exchange
14⅛% Series Due 2010	New York Stock Exchange
14⅜% Series Due 1987	New York Stock Exchange
12% Series Due 1990	New York Stock Exchange
13⅛% Series B Due 2010	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, par value $100

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

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at February 17, 1984 ..... $1,954,887,226

Number of shares of Common Stock, without par value, outstanding at February 17, 1984 99,715,015

Documents incorporated by reference:

The registrant has incorporated herein by reference certain sections of its proxy statement relating to the 1984 annual meeting of shareholders to provide information required by the following parts of this annual report:

Part III—Item 10., Directors and Executive Officers of the Registrant
—Item 11., Executive Compensation
—Item 12., Security Ownership of Certain Beneficial Owners and Management
—Item 13., Certain Relationships and Related Transactions

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DUKE POWER COMPANY

FORM 10-K

ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION FOR THE YEAR ENDED DECEMBER 31, 1983

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PART I.

Item 1. *Business.*

DUKE POWER COMPANY

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4,300,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1983, the Company's electric revenues amounted to approximately $2.4 billion, of which about 70% was derived from North Carolina and 30% from South Carolina. The Company ranks eighth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242 (Telephone No. 704-373-4011).

Factors Affecting the Industry. The electric utility industry in general has been experiencing problems in a number of areas including difficulty in obtaining sufficient return on invested capital and obtaining adequate rate increases when required; difficulty in obtaining sufficient capital on reasonable terms; the effects of inflation upon the cost of operations and upon construction costs; availability and increased cost of fuel for the generation of electric energy; costs and licensing delays related to compliance with changing environmental regulations; efforts to delay or prevent construction of nuclear generating and related facilities and to preclude or limit the use of existing facilities; uncertainties regarding the availability of reprocessing and storage facilities for spent nuclear fuel; and substantially increased capital outlays and longer construction periods required for larger, more complex generating facilities. The Company is currently experiencing these problems in varying degrees.

For a discussion of the developments affecting the Company, see "Construction Program" (pages 2 through 5), "Business—Rate Matters" (page 7), "Business—Fuel Supply" (pages 7 through 9), "Business—Regulation—*Environmental Matters*" (pages 9 and 10) and "Business—Regulation—*Nuclear Facilities*" (pages 10 and 11).

FINANCING PROGRAM

The Company estimates that it will obtain through the sale of securities and other external sources about 10% of its 1984-1986 total capital requirements, which include cost estimates of $1.5 billion for the construction program and $531 million for nuclear fuel. The balance of such requirements is expected to be obtained from retained earnings, depreciation and amortization, deferred taxes, investment tax credit and other internal sources. Such expectation is based in part upon receiving future rate increases as to which no assurance can be given.

The foregoing estimates of the Company's capital requirements expected to be obtained from external sources do not give effect to the proceeds of the proposed sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to Piedmont Municipal Power Agency (PMPA), a joint agency formed by a group of the Company's South Carolina municipal customers, as described under "Facilities Under Construction." The sale, which is contingent upon the arrangement of necessary financing by PMPA and subject to other contingencies, has been delayed by an appeal from an order of The Public Service Commission of South Carolina (PSC) authorizing the transaction. The Company has no assurance that such sale will be consummated.

In order to issue additional mortgage bonds and preferred stock, the Company must comply with earnings coverage and assets requirements contained in its mortgage indenture and articles of incorporation. Under the provisions of such indenture, additional bonds (other than certain types of refunding bonds) may not be issued unless the Company's available net earnings (as defined) for 12 consecutive calendar months within the 15 calendar months immediately preceding shall have been at least twice the amount of the annual interest charges on all bonds outstanding and applied for under the indenture. Additional bonds may be issued only

against cash, certain retired bonds and in the amount of 66⅔% of the aggregate of the net amounts of additional property certified to the trustee pursuant to the indenture.

Under its articles of incorporation, the Company may not issue additional shares of preferred stock unless, after giving effect thereto, (i) its net earnings available for dividends on the preferred stock for any 12 consecutive calendar months within the 15 calendar months preceding the month in which the additional shares are to be issued shall have been at least twice the dividend requirements for a 12-month period upon the entire amount of preferred stock and all other stock ranking prior to or on a parity with the preferred stock, and (ii) the total net assets of the Company at a date not more than 90 days prior to the date on which the additional shares are to be issued shall equal at least twice the aggregate amount payable upon the involuntary liquidation of the Company to the holders of the preferred stock and all other stock ranking prior to or on a parity with the preferred stock.

On the basis of these requirements, the Company's interest and dividend coverages for the years shown were as follows:

	Year Ended December 31		
	1983	1982	1981
Mortgage bond interest	4.31	3.60	2.61
Preferred stock dividends	6.98	5.61	5.96

The Company had available as of December 31, 1983 property additions (electric) which would permit the Company to issue under its mortgage indenture approximately $1.9 billion principal amount of additional bonds. As of such date the Company could have issued approximately $957 million of additional preferred stock within the above restrictions contained in its articles of incorporation.

CONSTRUCTION PROGRAM

The Company, utilizing its own construction and engineering force, carries on a continuous construction program. Such construction program and the estimated construction costs set forth below (a substantial portion of which has already been committed) are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rate increases), the availability and cost of capital in the financial markets, the availability and cost of labor, materials and equipment, licensing and other regulatory delays occasioned by opposition to nuclear power development or otherwise (see "Opposition to Nuclear Power Development") and changing regulatory and environmental standards (see "Business—Regulation—*Environmental Matters*"). The estimates of construction costs and the timing of construction expenditures are also subject to the sale of a portion of the Company's remaining interest in the Catawba Nuclear Station to PMPA.

In April 1983 the Company announced the cancellation of Unit 1 of the Cherokee Nuclear Station citing a slower growth in the demand for electricity, a changing pattern in that growth and more economical means of meeting such changed pattern as reasons for such cancellation. The Company believes, however, that alternative sources of energy will be necessary and available to meet the anticipated needs of its customers during the mid-1990s. Cancellation of Units 2 and 3 of the Cherokee Nuclear Station was announced in 1982. As of December 31, 1983, the balance of investment in the canceled Cherokee Nuclear Station, excluding land and net of amortization, was $625 million. Additional costs relating to the cancellations are not expected to be significant.

The North Carolina Utilities Commission (NCUC) and the PSC authorized the Company to recover the costs of abandonment of the Cherokee Nuclear Station over a 10-year period. Neither regulatory body allowed any return on the unamortized portion of such costs. The Company also has requested recovery of the abandonment costs related to the Cherokee Nuclear Station in its wholesale jurisdiction.

Estimated Costs

Cost estimates for the construction program, including the acquisition of nuclear fuel, for each of 1984, 1985 and 1986 and for the three-year period 1984-1986, as now scheduled, assuming no further sale of the Company's remaining interest in the Catawba Nuclear Station, are as follows (in millions of dollars):

Type of Facilities	1984	1985	1986	Total
Generation*	$287	$248	$204	$ 739
Transmission	36	30	35	101
Distribution	155	170	186	511
Other	65	64	61	190
Total	$543**	$512**	$486**	$1,541**
Nuclear Fuel	$135	$205	$191	$ 531

* Cost estimates for the three-year period 1984-1986 include approximately $150 million attributable to the portion of the Catawba Nuclear Station which the Company has agreed to sell to PMPA. (See "Facilities Under Construction.")

** The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation.

The Company has experienced higher costs of construction of new facilities as a result of recurring increases in the costs of materials, labor and capital, and increasing capital commitments attributable to more stringent regulatory requirements. However, the Company believes that in recent years it has been able to construct generating units at a lower cost per KW than generally experienced by other utilities for units of comparable type and vintage.

During the three-year period 1981-1983, gross property additions (including nuclear fuel) and net retirements amounted to approximately $2.2 billion and $1.2 billion, respectively, resulting in a net increase of approximately $1.0 billion, or 14%, in gross plant. Net retirements include the portions of the Catawba Nuclear Station sold to certain of the Company's cooperative customers (see "Facilities Under Construction") and amounts related to the cancellation of several nuclear projects.

Facilities Under Construction

The following table sets forth the major generating facilities of the Company currently under construction which are to be added to its present generating capability of 13,594,000 KW:

Unit and Location	Net KW Capability	Energy Source	Company Ownership (%)	Date of Planned Operation(1)	Estimated Construction Cost per KW(2)	Total Estimated Construction Costs(2)	Amounts Expended Through 1983(2)
						(Dollars in millions)	
Catawba 1	1,145,000	Nuclear	25	1985	$1,703(3)	$975(3)	$606(3)
Catawba 2	1,145,000	Nuclear	25	1987	$1,703(3)	$975(3)	$606(3)
(Southwest of Charlotte, in South Carolina)							
Bad Creek(4)	500,000	Hydro	100	1991	967	967	31
(Oconee County, South Carolina)	500,000	Hydro	100	1992	967	967	31

(1) Based on past experience, operational dates may vary due to construction delays, difficulties which may be encountered in obtaining regulatory approvals or in obtaining capital at reasonable costs, changes in load forecasts and other factors (see "Business—Regulation").

(2) These amounts exclude the costs of initial fuel cores.

(3) These amounts do not include the costs of the undivided interests sold to the North Carolina Municipal Power Agency Number 1 in 1978 and to North Carolina Electric Membership Corporation and Saluda

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River Electric Cooperative Inc. in 1981, and assume no further sale of the Company's remaining interest in the Catawba Nuclear Station.

(4) The Bad Creek Hydroelectric Station, a pumped storage facility, will consist of four 250,000 KW units.

In order to reduce its need for external financing, the Company, in 1978, sold to the North Carolina Municipal Power Agency Number 1 (NCMPA), a public body created by a group of the Company's North Carolina municipal customers, a 75% undivided interest in Unit 2 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. In 1981, the Company also sold to the North Carolina Electric Membership Corporation (NCEMC) and Saluda River Electric Cooperative Inc. (Saluda), whose members were, prior to November 1, 1983, cooperative wholesale customers of the Company, a 75% undivided interest in Unit 1 of the Catawba Nuclear Station and a 37½% undivided interest in the support facilities of that Station. The Company will continue to construct the facility and the purchasers will finance their respective portions of the construction costs by continued monthly progress payments.

The transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use that portion of the capacity not then required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also provide for the maintenance by the Company of a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station. NCMPA invoked this provision effective July 1, 1983, thereby making NCMPA an operating entity serving its participating members. NCEMC and Saluda have also invoked this provision effective November 1, 1983, thereby making NCEMC and Saluda operating entities, serving their participating members. The Company does not anticipate that the implementation of these provisions will have a material effect on earnings.

The Company and PMPA have an agreement with respect to the purchase by PMPA of the remaining 25% interest in Unit 2 of the Catawba Nuclear Station on substantially the same terms and conditions as the sale to NCMPA. Should the sale be consummated in late 1984, the Company would receive about $430 million at that time. However, the Company has no assurance that such sale will be consummated.

During 1983, NCMPA's participating members, which, until June 30, 1983, were wholesale customers of the Company, accounted for approximately 5% of KWH sales and approximately 4% of revenues, and PMPA's participating municipalities accounted for approximately 2% of KWH sales and approximately 2% of revenues. The participating members of NCEMC and Saluda which, until October 31, 1983, were wholesale customers of the Company, accounted for approximately 7% of KWH sales and approximately 6% of revenues.

Hearings are currently being held before the Nuclear Regulatory Commission (NRC) with respect to the Company's application for an operating license for the Catawba Nuclear Station. The NRC Office of Investigation is conducting an inquiry into allegations of irregularities in quality assurance procedures. The results of this investigation may become an issue in the licensing of the Station.

Load Management

The Company currently is engaged in a comprehensive load management program designed to reduce the growth in peak demand without restricting the continued economic development of the Company's service area. Such program includes, among other things, promotion of energy-efficient building structures and appliances, use of residential conservation rates, use of interruptible rates for large customers, control by the Company (with customers' consent) of residential electric water heaters and air conditioners during peak demand periods and time-of-day pricing to a limited number of customers. The current and planned aspects of such program are designed to reduce the growth in peak demand by approximately 4,180,000 KW in the summer of 1998 (from estimated peak demands at those times without load management) and to enhance generating reserve margins through the ability to interrupt approximately 1,158,000 KW in 1998. The Company has currently documented reductions through accumulated load management of approximately 1,417,000 KW for its summer peak load and approximately 1,867,000 KW for its winter peak load.

Through 1990, the Company estimates a minimum reserve margin, after giving effect to the interruptible load, of approximately 25% of its anticipated peak load requirements. (For information about the Company's peak loads, see "Business—Energy Requirements and Capability.")

General

The complexity of present-day electric utility technology and the time required for the construction of generating facilities and for the completion of the licensing and other regulatory proceedings relating thereto have compelled the Company, as well as other electric utilities, to make substantial investments in the construction of such facilities prior to the completion of licensing and regulatory proceedings. At December 31, 1983, the Company had $606 million invested in its portion of the Catawba Nuclear Station for which operating licenses have not been issued. Under present NRC procedures, an operating license may be issued only when construction of a nuclear unit has been completed. Accordingly, the Company is necessarily making substantial investments in its facilities before regulatory proceedings are completed. There is no assurance that the necessary operating licenses and authorizations will be issued for such facilities.

Opposition to Nuclear Power Development

The development of nuclear power continues to be a subject of public controversy. Various groups have engaged in public protests, filed suits and participated in administrative proceedings and other activities, claiming that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. In addition, restrictive legislation relating to nuclear power has been proposed in Congress and in several state legislatures and referenda have been proposed to the electorate in certain states. Some of the claims made by such groups, if they should prevail, or the existence of the controversy itself, could delay or prevent the construction of nuclear generating units presently under construction, or cause substantial modifications to or shutdowns of existing units.

BUSINESS

Service Area

The Company supplies electric service directly to approximately 1,357,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold through contractual arrangements to NCMPA, NCEMC and Saluda and at wholesale to 18 other incorporated municipalities and to several private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, tobacco, furniture and chemical industries are of major significance to the economy of the area; and there is a diversity of other industrial activity, including the manufacture of metal products, paper and allied products, food products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $374 million of the Company's revenues for 1983, representing 15% of electric revenues and 47% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1983, its generation of electric energy for 1983, and certain corresponding information presently projected for 1984:

			Generating Capability(1)			Generation		
			Actual 1983		Projected 1984(2)	Actual 1983		Projected 1984(2)
Source	Facility		KW	%	%	KWH (millions)	%	%
Coal	Belews Creek		2,240,000			14,482		
	Marshall		2,030,000			9,815		
	Allen		1,100,000			3,175		
	Cliffside		770,000			2,853		
	Others		1,460,000			2,141		
		Total	7,600,000	56.7	49	32,466	55.4	51
Nuclear	Oconee		2,580,000			17,909		
	McGuire		1,180,000			7,150(3)		
		Total	3,760,000	28.0	36	25,059	42.7	48
Hydro and Other	26 stations and combustion turbines		2,051,000	15.3	15	2,122	3.6	3
Purchased Power, Net(4)	—		—	—	—	(1,003)	(1.7)	(2)
		Total	13,411,000(5)	100.0	100	58,644	100.0	100

(1) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(2) Projected figures are based on the assumption that required fuel is available and that there are no unforeseen contingencies.

(3) Includes generation of 2,515 million KWH during testing of McGuire Unit 2.

(4) The purchasers of the Catawba Nuclear Station are entitled to receive power from the McGuire Nuclear Station under reliability exchange agreements. Accordingly, the Company's 1983 generation and projected generation for 1984 are affected by these agreements.

(5) Unit 2 of the McGuire Nuclear Station began commercial operation on March 1, 1984. On the same date, generating capability was reduced by 997,000 KW due to the removal from firm capability of certain older coal-fired units.

According to industry statistics through 1982, the Company ranked first in the nation for the last nine consecutive years and for 11 of the last 13 years in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that the four

units at the Marshall Steam Station and the two units at the Belews Creek Steam Station were the six most efficient in the nation in 1982. A Company station has been ranked first in efficiency in 14 of the last 16 years through 1981. Statistics supplied to the NRC by utilities demonstrate that the Company's Oconee Nuclear Station was the most efficient pressurized water reactor nuclear facility in the nation in 1982. The net capacity factors for the Oconee Nuclear Station were 61% for 1981, 47% for 1982 and 79% for 1983. The reduction in the net capacity factor for 1982 was primarily due to planned ten-year inspection outages.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The 1983-1984 winter peak load of 10,863,000 KW occurred on February 8, 1984 and the 1983 summer peak load of 11,554,000 KW occurred on August 23, 1983. The 1982-1983 winter peak load of 10,378,000 KW occurred on January 19, 1983 and the 1982 summer peak load of 10,097,000 KW occurred on July 28, 1982. The Company has reduced its peak load growth forecast through 1998 to growth rates ranging from a high of approximately 2.8% to a low of approximately 2.4% (compounded annually) with no specific forecast within that range.

In March 1983 the NCUC commenced required hearings regarding future growth in the use of electricity and the need for future generating capacity in North Carolina. The NCUC issued its order on December 1, 1983, forecasting peak load growth within a range of a high of 3.5% and a low of 1.4%.

Federal Energy Legislation

Congress adopted a national energy act in 1978 dealing with, among other things, utility rate design, including restrictions on the use of fuel adjustment clauses. Other sections of the legislation give the Federal Energy Regulatory Commission (FERC) increased authority to order interconnections, power pooling and wheeling of power. The Company is presently unable to assess the impact of this legislation on its operations.

Rate Matters

The NCUC and the PSC must approve the Company's rates for retail sales within the respective States. FERC must approve the Company's rates for sales under its wholesale rate schedules. Participating members of NCMPA, effective July 1, 1983, and participating members of NCEMC and Saluda, effective November 1, 1983, are served under contractual arrangements between such entities and the Company (see "Construction Program—Facilities Under Construction"). In 1983 such members accounted for approximately 85% of the Company's wholesale revenues.

General Rate Increases. Information concerning rate increases requested or implemented by the Company between January 1, 1981 and December 31, 1983 is set forth in Note 2 in Notes to Financial Statements. Intervenors have appealed on various grounds the rate increase authorized by the NCUC, effective December 1981, referred to in such Note.

On February 22, 1984 the PSC authorized a rate increase with respect to the Company's South Carolina retail customers, effective March 1, 1984, which is expected to increase retail revenues by approximately $99.7 million, or 73% of the revenues requested by the Company in its application filed in September 1983. The PSC has denied a request by intervenors for a rehearing on the matter. On March 1, 1984 the Company placed into effect, on an interim basis subject to refund, a $12.7 million rate increase with respect to its wholesale customers.

In the Company's most recent rate orders, the NCUC allowed a jurisdictional rate of return on common equity of 15.25% and the PSC allowed a jurisdictional rate of return on common equity of 14.75%.

Fuel Cost Adjustment Procedures. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. (See Note 1 in Notes to Financial Statements.)

Construction Work in Progress. The NCUC is permitted in its discretion to include construction work in progress in rate base after giving consideration to the public interest and the Company's financial stability. The NCUC has instituted a rule-making proceeding to determine what guidelines, if any, for inclusion of CWIP in rate base should be adopted for electric utilities. The PSC may include CWIP in rate base in its discretion.

Fuel Supply

The Company presently relies principally on coal and nuclear for the generation of electric energy, but it anticipates relying on nuclear power to a greater extent in the future (see "Construction Program"). The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source			Average Cost per Million BTU on a Burned Basis		
	Year Ended December 31			Year Ended December 31		
	1983	1982	1981	1983	1982	1981
Coal	55.4%	70.5%	73.0%	189.55¢	190.87¢	178.39¢
Nuclear	42.7	27.2	24.4	54.19	55.04	46.98
Oil and Gas	—	—	.3	530.82	439.40	416.17
All Fuels (cost based on weighted average)	98.1	97.7	97.7	131.66	149.86	144.33
Hydroelectric*	3.6	2.8	1.4			
Purchased Power, Net	(1.7)	(.5)	.9			
	100.0%	100.0%	100.0%			

* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

Coal. The Company obtains its coal under long-term supply contracts with mining operators utilizing both deep and surface mining, by open market purchases and, until recently, through its own mining operations. During 1983, the Company obtained its coal requirements approximately as follows: 92% (10.2 million tons) under long-term contracts, 7% (.8 million tons) from its own mining operations and 1% (.1 million tons) by open market purchases. On March 22, 1984, the Company had on hand a coal supply of approximately 93 days.

The Company has sold all of its mining operations, the last sale having been consummated on August 4, 1983. A $30 million provision for a loss (net of applicable income taxes) was recorded in December 1982 in anticipation of the sales. No additional loss provision was necessary in 1983. The Company has replaced a portion of the coal formerly received from these operations through additional long-term contracts. The Company decided to sell these properties after the NCUC, in its November 1, 1982 rate order, limited the recoverable cost of coal from these operations.

The Company's long-term supply contracts, all of which have price adjustment clauses, have expiration dates ranging from 1986 to 2000. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia.

The Company also purchases coal on a spot basis to maintain inventory and to cover load fluctuations. There is no assurance that coal will be available on a spot basis in the future or that it will be available at reasonable prices. The Company purchased coal on a spot basis at an average delivered cost of $35.80 per ton, or 148.0¢ per million BTU, during 1983, as compared with an average delivered cost of $36.93 per ton, or 152.5¢ per million BTU, for the year 1982.

The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the emission limitation for sulfur dioxide for existing facilities (see "Regulation—*Environmental Matters*").

The Company estimates that through the year 1995 its existing coal-fired generating units (see table under "Energy Requirements and Capability") will burn a total of approximately 130 million tons of coal. The Company presently expects to obtain the major portion of this estimated requirement from long-term agreements.

The Economic Regulatory Administration of the Department of Energy is authorized, under prescribed conditions, to allocate coal to achieve, among other things, the distribution of available low sulfur fuels on a priority basis to areas designated by the United States Environmental Protection Agency (EPA).

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is

removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations (see "Energy Requirements and Capability" and "Construction Program") through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1993	1993	2014	1989
McGuire	1993	1993	2014	1989
Catawba	1993	1993	2014	1989

Approximately 75% of the Company's commitments for uranium materials included in the preceding table is expected to be obtained from Rio Algom, Ltd., a Canadian supplier. Deliveries to the Company by such supplier, which began in 1981, are subject to permits and export licenses from various Canadian governmental agencies, including the Atomic Energy Control Board, the Department of Industry, Trade and Commerce and the Uranium Exports Review Panel.

The Company purchased uranium material during 1983 at an average price of approximately $34 per pound. However, such price is expected to be greater in future years. The Company's material nuclear supply contracts generally contain *force majeure* provisions and provide for price escalation under certain conditions.

The Company has received regulatory approvals which will enable it to provide adequate storage facilities for its spent nuclear fuel through 1992. Consideration is being given to expanding system storage capacity through 1998 by additional reracking, through transshipment of spent fuel between stations, and through the use of developing storage technologies such as rod consolidation. The Nuclear Waste Policy Act of 1982 requires that the Department of Energy (DOE) begin disposing of spent fuel not later than January 31, 1998. The Company has entered into the required contracts with DOE and began making payments in July 1983 for fuel currently being utilized.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, EPA and state environmental agencies and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities (see "Construction Program").

Environmental Matters. The Company is subject to Federal, state and local regulation with respect to environmental matters, including air and water quality. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1984-1986 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $102 million, including $49 million in 1984 and $32 million in 1985. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

AIR QUALITY. In 1971, pursuant to the Clean Air Act of 1970 (the 1970 Act), EPA promulgated primary and secondary ambient air quality standards with respect to certain air pollutants including particulates, sulfur oxides and nitrogen oxides. Pursuant to such regulations, North Carolina and South Carolina have adopted implementation plans, which have been approved by EPA, containing air emission standards which were generally designed to achieve the primary ambient air quality standards by 1975 and the secondary ambient air quality standards within a reasonable time thereafter. The Company believes it is presently in substantial compliance with such implementation plans. The 1977 amendments to the 1970 Act include, among other things, authority for EPA to impose substantial delayed compliance penalties for failure to comply with applicable emission limitations after July 1, 1979 and civil penalties of up to $25,000 per day for facilities found to be in violation of an applicable implementation plan provision.

Although the Company believes it has installed the best available control technology in its coal-fired generating stations, it determined that it could not consistently and continuously meet the stringent mass

emission standards for particulates specified in the North Carolina implementation plan even though each unit had successfully completed stack performance tests. The Company filed for and was granted by the North Carolina Environmental Management Commission (EMC) in 1979 a three-year variance from the mass emission limits. The variance was temporarily extended by the EMC and subsequently replaced by a permanent mass emission standard which includes stringent annual tonnage limits for each boiler unit in addition to mass emission limits for particulates. The new regulation has been submitted by the State to EPA for approval as a revision to the North Carolina implementation plan.

On December 21, 1983, EPA published notice of its proposal to approve the new mass emission limits contingent on an additional submission by the State to document compliance with regulations for Prevention of Significant Deterioration of air quality. EPA has proposed no action on annual tonnage limits as a matter of policy. Such new regulation also requires automatic monitoring equipment on each boiler unit to measure continuously the opacity of particulate emissions. The EMC has approved a Special Order by Consent to authorize a delay in the installation of such equipment on 11 older units currently without such equipment pending re-evaluation by the EMC of the new regulation.

Changes in state implementation plan requirements could require the Company to incur substantial capital costs for pollution control equipment. Additionally, if legislation relating to air quality being considered by Congress is enacted, a rollback in sulfur dioxide emission limits for electric utility boilers might be required.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1972 require permits to ensure compliance with its provisions. The Company has received such permits.

In 1974, EPA established guidelines for steam electric generating plant discharges setting effluent limitations for existing sources and standards of performance for new sources. These guidelines imposed a "no discharge" of heat requirement on certain existing generating units and units under construction. Such guidelines were challenged in a suit filed in the United States Court of Appeals for the Fourth Circuit *(Appalachian Power Company, et al. v. Train)*. In a decision issued in 1976, the Court set aside and remanded to EPA for further consideration portions of the guidelines relating to the "no discharge" of heat requirement. The Company is unable at this time to determine what effect these developments will have on its operations.

OTHER ENVIRONMENTAL REGULATIONS. North Carolina has enacted a declaration of environmental policy requiring all State agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. Legislation in South Carolina also requires consideration by the PSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation and certain transmission facilities. North Carolina and South Carolina have adopted regulations implementing the Resources Conservation and Recovery Act which are in compliance with such Act.

Polychlorinated biphenyls are regulated by provisions of the Toxic Substances Control Act. Major portions of the regulations issued by EPA implementing such provisions have been appealed. The Company will be unable to determine the effect, if any, those regulations will have on its operations until the appeal is decided.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, known as "Superfund", became law in 1980. It requires the reporting of releases of hazardous substances into the environment and the notification to EPA of hazardous waste facilities that are not subject to other regulations. The Company has implemented reporting procedures in order to comply with the Act.

GENERAL. The Company cannot estimate the effect of existing and potential regulations upon any of its existing and proposed facilities. However, developments in these and other areas of regulation have in the past required the Company to modify or replace equipment and may in the future delay construction and operation of new or existing facilities at costs which could be substantial.

Nuclear Facilities. NRC regulations require consideration of both radiological and environmental issues prior to granting construction permits and operating licenses for nuclear power plants. These regulations currently permit public intervention with respect to issuances of permits and licenses.

The NRC recently requested the Company to study its Oconee reactor vessels for thermal shock effects of emergency core cooling system operations during a loss of feedwater event, as well as other transients which

might induce rapid overcooling of the system. Preliminary analyses of the Oconee units conducted by the Company and the manufacturer, Babcock & Wilcox Company, have indicated that the vessels as constructed are adequate to permit safe operation for the remainder of their projected licensed lives. The present position of the staff of the NRC is that the units can operate safely pending completion of its analysis of the matter. However, should modification be warranted upon completion of such analysis, the cost of modification is not expected to be material.

The Company has insured against public liability claims resulting from nuclear incidents to the full $580 million limit on liability under the Price-Anderson Act. The maximum available private insurance of $160 million has been purchased and the remaining $420 million has been provided through a mandatory industry-wide program of self-insurance, under which licensees could be assessed in the event of a nuclear incident involving any licensed facility in the nation up to $5 million for each of its licensed reactors and up to $10 million a year for each of its licensed reactors in the event of more than one incident. Such nuclear insurance coverage does not include coverage of the plant facilities. To cover possible damage to these facilities, the Company maintains property damage insurance with Nuclear Mutual Limited, a Bermuda mutual insurance company of which the Company is a member, in the maximum amount available from such insurer, which is presently $500 million, or the insurable value of the facilities, whichever is less. The Company has purchased from Nuclear Electric Insurance Limited (NEIL), a Bermuda mutual insurance company of which it is a member, an additional $425 million of property damage insurance through its Excess Property Insurance Program. The Company also has purchased an additional $68 million of property damage insurance through a pool of stock and mutual insurance companies. In connection with the sale in 1978 of a portion of its interest in the Catawba Nuclear Station (see "Construction Program"), the Company placed through a pool of stock and mutual insurance companies separate property damage insurance on that Station (including the interest sold) to the extent of $460 million.

NEIL also provides insurance against the increased cost of generation or purchased power resulting from the accidental outage of a nuclear unit. The Company's Oconee Nuclear Station and Unit 1 of the McGuire Nuclear Station are insured for up to $2.5 million a week per unit, after a 26-week deductible period, with declining amounts per unit where more than one unit is involved. Coverages continue at 100% for 52 weeks and at 50% for an additional 52 weeks. This is presently the maximum amount of coverage available.

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for a term expiring in 2016 covering a power generation development on the upper tributaries of the Savannah River in northwestern South Carolina. Hydroelectric and pumped storage units in such development, with a nameplate rating of 750,000 KW, have been completed. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which it considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems and rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSC, respectively, of all areas outside municipalities in such States to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to

competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSC.

Employees

At December 31, 1983, the Company employed approximately 21,000 persons, of whom approximately 7,700 were engaged in generating plant construction including design and engineering. About 1,850 electrical operating employees are represented by the International Brotherhood of Electrical Workers with which the Company has a labor agreement which expires on September 30, 1984.

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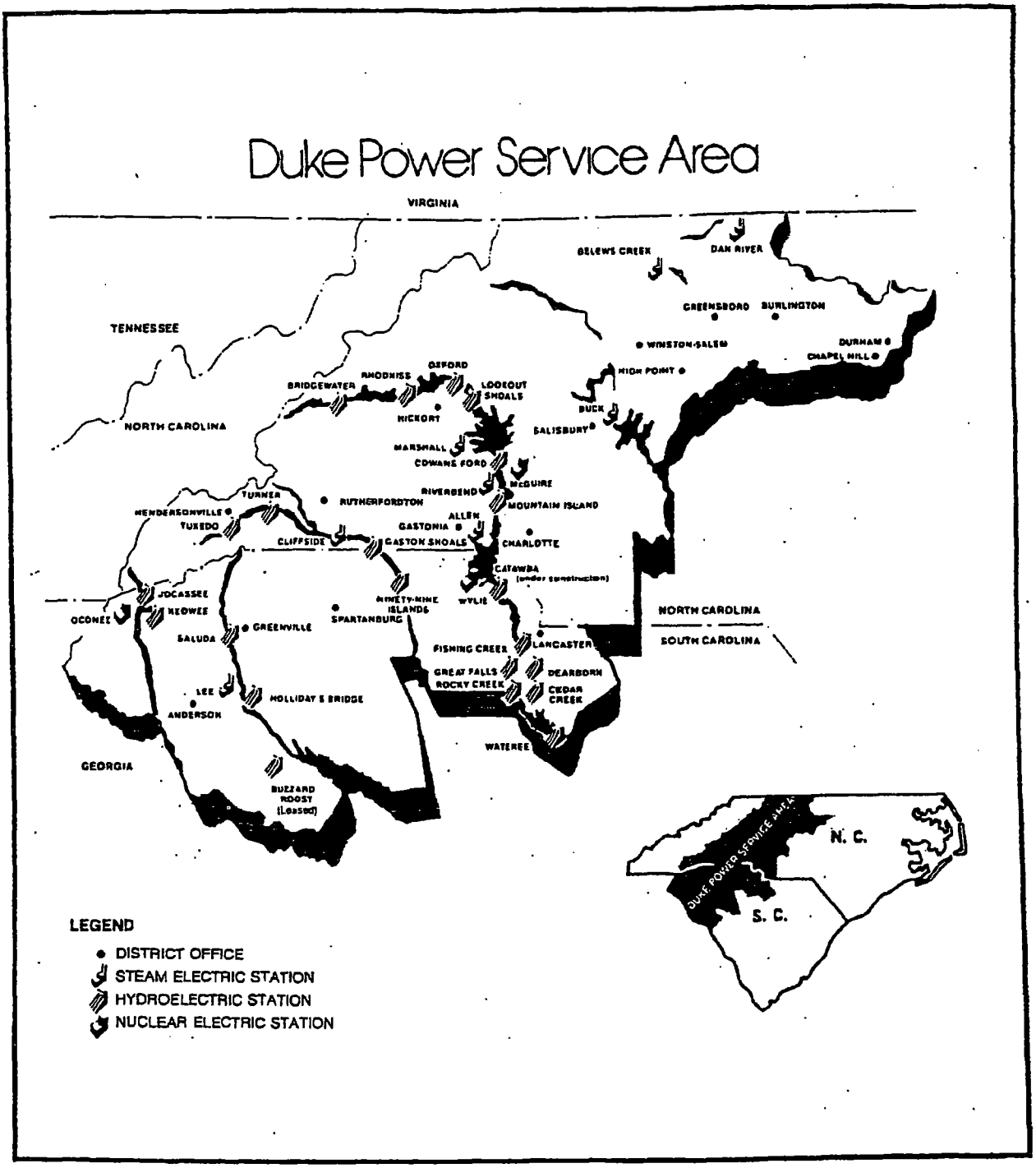
Duke Power Service Area
VIRGINIA
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
GEORGIA
BELEWS CREEK
DAN RIVER
GREENSBORO
BURLINGTON
WINSTON-SALEM
DURHAM
CHAPEL HILL
HIGH POINT
OXFORD
RHODHISS
BRIDGEWATER
LOOKOUT SHOALS
NICKORT
BUCK
SALISBURY
MARSHALL
COWANS FORD
MCGUIRE
RIVERBEND
TURNER
RUTHERFORDTON
MOUNTAIN ISLAND
HENDERSONVILLE
TUXEDO
ALLEN
GASTONIA
CLIFFSIDE
GASTON SHOALS
CHARLOTTE
CATAWBA
JOCASSEE
KEOWEE
OCONEE
NINETY-NINE ISLANDS
WYLIE
SPARTANBURG
GREENVILLE
SALUDA
FISHING CREEK
LANCASTER
GREAT FALLS
ROCKY CREEK
DEARBORN
CEDAR CREEK
LEE
ANDERSON
HOLLIDAY'S BRIDGE
WATEREE
BUZZARD ROOST (Leased)
N. C.
S. C.
DUKE POWER SERVICE AREA
LEGEND
DISTRICT OFFICE
STEAM ELECTRIC STATION
HYDROELECTRIC STATION
NUCLEAR ELECTRIC STATION

OPERATING STATISTICS

	Year Ended December 31				
	1983	1982	1981	1980	1979
Sources of Electric Energy					
Millions of kilowatt-hours:					
Generated—net output:					
Coal	32,466	38,927	42,513	40,984	37,404
Nuclear	25,059	15,009	14,229	14,213	14,228
Hydro	2,114	1,569	843	1,820	2,809
Oil and gas	8	7	146	203	163
Total generated	59,647	55,512	57,731	57,220	54,604
Net interchange and purchased power	(1,003)	(301)	494	(472)	(512)
Losses and company use	(4,493)	(3,831)	(4,677)	(4,437)	(3,769)
Total energy sales	54,151	51,380	53,548	52,311	50,323
Average Cost Per Ton of Coal Burned	$47.24	$46.80	$43.24	$37.85	$35.86
Electric Energy Sales					
Millions of kilowatt-hours:					
Residential	14,219	13,711	13,861	13,765	12,832
General service	10,339	10,087	9,731	9,395	8,778
Industrial					
Textile	10,115	9,215	10,101	10,152	10,394
Other	10,792	10,130	10,566	9,908	9,866
Wholesale and other energy sales	8,686	8,237	9,289	9,091	8,453
Total energy sales	54,151	51,380	53,548	52,311	50,323
Electric Revenues					
Thousands of dollars:					
Residential	$ 806,085	$ 741,255	$ 624,986	$ 565,633	$ 499,936
General service	521,568	485,064	386,141	340,691	303,858
Industrial					
Textile	374,138	335,727	293,081	263,024	254,877
Other	419,755	384,191	320,838	271,766	253,728
Wholesale and other energy sales	324,595	309,241	270,623	232,506	201,938
Other electric revenues	(25,889)	(10,998)	12,785	9,202	(21,780)
Total electric revenues	$2,420,252	$2,244,480	$1,908,454	$1,682,822	$1,492,557
Number of Customers—End of Year					
Residential	1,167,846	1,139,248	1,125,371	1,105,035	1,078,419
General service	175,142	168,897	167,282	165,522	161,833
Industrial					
Textile	1,323	1,302	1,313	1,324	1,326
Other	6,588	6,459	6,410	6,264	6,149
Wholesale and other energy sales	6,276	6,403	6,326	6,260	5,950
Total customers	1,357,175	1,322,309	1,306,702	1,284,405	1,253,677
Residential Customer Statistics					
Average number for year	1,158,123	1,136,431	1,118,534	1,095,933	1,068,194
Average annual use—KWH	12,278	12,065	12,392	12,560	12,013
Average annual billing	$696.03	$652.27	$558.75	$516.12	$468.02
Average Annual Billed Revenue Per KWH					
Residential	5.67¢	5.41¢	4.51¢	4.11¢	3.90¢
General service	5.04¢	4.81¢	3.97¢	3.63¢	3.46¢
Industrial	3.80¢	3.72¢	2.97¢	2.67¢	2.51¢
Wholesale and other energy sales	3.74¢	3.75¢	2.91¢	2.56¢	2.39¢

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age*
W. S. Lee**	Chairman of the Board and Chief Executive Officer	1982	54
D. W. Booth**	President and Chief Operating Officer and Director	1982	59
W. H. Grigg**	Executive Vice President, Finance and Administration, and Director	1982	51
W. H. Owen**	Executive Vice President, Engineering and Construction, and Director	1982	57
A. C. Thies**	Executive Vice President, Power Operations, and Director	1982	62
Steve C. Griffith, Jr.**	Senior Vice President and General Counsel and Director	1982	50
John D. Hicks**	Senior Vice President, Public Affairs, and Director	1977	60
Henry L. Cranford	Senior Vice President, Division Operations	1982	56
Donald H. Denton, Jr.	Senior Vice President, Marketing and Rates	1982	46
Frank A. Jenkins	Senior Vice President, Transmission and Distribution	1982	64
Thomas C. Berry	Vice President, Southern Division	1976	53
Ralph W. Bostian	Vice President, Production Support	1982	57
J. Kenneth Clark	Vice President, Corporate Communications	1981	51
L. C. Dail	Vice President, Design Engineering	1978	58
Robert L. Dick	Vice President, Construction	1971	56
George W. Ferguson, Jr.	Vice President and Deputy General Counsel	1982	51
M. T. Hatley, Jr.	Vice President, Rates	1979	61
E. N. Hedgepeth, Jr.	Vice President, Distribution	1982	56
S. T. Lattimore	Vice President, Finance Administration	1982	57
John F. Lomax	Vice President, Western Division	1980	44
Joseph G. Mann	Vice President, Northern Division	1973	60
Paul H. Mann, Jr.	Vice President, Operation	1978	61
Paul G. Martin	Vice President, Eastern Division	1982	51
Dwight B. Moore	Vice President, Central Division	1980	62
William O. Parker, Jr.	Vice President, Fossil Production	1982	59
E. Bruce Shuler	Vice President, Transmission	1982	56
William R. Stimart	Vice President, Regulatory Affairs	1979	52
George E. Stubbins	Vice President, Information Systems	1982	43
Hal B. Tucker	Vice President, Nuclear Production	1982	55
Fred E. West, Jr.	Vice President, Charlotte Division	1981	47
James W. White	Vice President, General Services	1979	58
Lewis F. Camp, Jr.	Secretary and Associate General Counsel	1980	55
Norman P. Morrow	Controller	1982	36
Richard J. Osborne	Treasurer	1981	33

* As of March 1984.
** Member of the Executive Committee.

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Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years except for J. Kenneth Clark and Norman P. Morrow. Mr. Clark served as Public Affairs Director of Mars, Inc., confectioner, from July 1978 to May 1981 when he joined the Company as Vice President, Corporate Communications. He served as Corporate News Bureau Director of Monsanto Company, a diversified chemical manufacturer, from 1976 to 1978. Mr. Morrow was an accountant with the firm of Deloitte Haskins & Sells from 1970 to 1980, when he joined the Company as Assistant Controller.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Item 2. *Properties.*

The map on page 13 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V—Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see Item 1.—"Construction Program—Facilities Under Construction".

Item 3. *Legal Proceedings.*

Reference is made to Item 1.—"Construction Program" for information relating to licensing proceedings before the NRC with respect to the Company's Catawba Nuclear Station.

Reference is made to Item 1.—"Business—Rate Matters" for information relating to an appeal taken from a rate order previously obtained by the Company from the NCUC. Intervenors appealed an order of the PSC issued in August 1980 granting a rate increase of $23.4 million based on a test year ended June 30, 1979, seeking its reversal or modification and refunds. The Court of Common Pleas, Richland County, upheld the order. On appeal, the South Carolina Supreme Court reversed and remanded the case to the PSC for further proceedings. Intervenors have also appealed an order of the NCUC issued in February 1982 adjusting rates based on changes in fuel cost, seeking its reversal or modification and refunds. The North Carolina Court of Appeals remanded the order to the NCUC for a redetermination of fuel costs.

Item 4. *Submission of Matters to a Vote of Security Holders.*

No matters were submitted to a vote of the Company's security holders during the last quarter of 1983.

PART II.

Item 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters.***

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1983, there were approximately 124,600 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by *The Wall Street Journal* as composite transactions:

Common Stock	Dividends per Share	Price Range	
		High	Low
1983 by Quarter			
Fourth	$0.59	26⅜	24
Third	0.59	24⅛	21¾
Second	0.57	24	22⅜
First	0.57	24	22
1982 by Quarter			
Fourth	$0.57	23½	20⅝
Third	0.57	23⅝	20½
Second	0.55	24	20⅜
First	0.55	23½	20⅜

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Item 6. *Selected Financial Data.*

DUKE POWER COMPANY

SELECTED FINANCIAL DATA

	Year Ended December 31				
	1983	1982	1981	1980	1979
	(Dollars in thousands, except per share figures)				
CONDENSED STATEMENTS OF INCOME					
Electric revenues	$ 2,420,252	$ 2,244,480	$ 1,908,454	$ 1,682,822	$ 1,492,557
Electric expenses	1,971,038	1,854,712	1,632,104	1,402,722	1,238,680
Electric operating income	449,214	389,768	276,350	280,100	253,877
Other income	213,001	175,048	254,043	208,365	168,612
Income before interest deductions	662,215	564,816	530,393	488,465	422,489
Interest deductions	230,938	214,939	194,142	177,374	147,729
Income before extraordinary item	431,277	349,877	336,251	311,091	274,760
Extraordinary item	—	48,304	—	—	—
Net income	431,277	398,181	336,251	311,091	274,760
Dividends on preferred and preference stocks	62,600	62,164	57,895	58,612	52,562
Earnings for common stock	$ 368,677	$ 336,017	$ 278,356	$ 252,479	$ 222,198
RATIO OF EARNINGS TO FIXED CHARGES (SEC method)	3.46	2.98	2.73	2.65	2.86
COMMON STOCK DATA					
Shares of common stock					
—End of year (thousands)	99,634	95,949	88,483	86,294	79,489
—Average (thousands)	97,784	93,679	87,313	81,985	77,168
Per share of common stock					
Earnings before extraordinary item	$ 3.77	$ 3.07	$ 3.19	$ 3.08	$ 2.88
Extraordinary item	—	0.52	—	—	—
Earnings	$ 3.77	$ 3.59	$ 3.19	$ 3.08	$ 2.88
Dividends	$ 2.32	$ 2.24	$ 2.08	$ 1.95	$ 1.83
Book value—end of year	$ 26.26	$ 24.89	$ 23.83	$ 22.82	$ 22.12
Market price—high-low	$26⅞-21¾	$ 24-20⅜	$22½-15⅞	$19¼-14⅛	$20⅝-16¼
—end of year	$ 25⅛	$ 23¼	$ 20⅝	$ 18⅛	$ 17¼
TOTAL ASSETS	$ 7,379,445	$ 7,057,780	$ 6,531,044	$ 6,328,174	$ 5,615,372
LONG-TERM DEBT	$ 2,745,889	$ 2,712,372	$ 2,545,694	$ 2,594,008	$ 2,300,488
PREFERRED STOCKS WITH SINKING FUND REQUIREMENTS	$ 295,053	$ 304,026	$ 308,674	$ 316,559	$ 268,500

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Results of Operations

Net Income and Dividends

From 1979 to 1983, earnings per share increased at an annual rate of 7 percent, from $2.88 to $3.77. Total Company earned return on average common equity was 14.8 percent for 1983. During the past five years, the return achieved on the Company's retail electric business has been consistently below the return found fair and reasonable by the North Carolina Utilities Commission (NCUC). The NCUC currently allows a 15.25 percent return on common equity. Dividends per share increased at an annual rate of 6 percent, from $1.83 in 1979 to $2.32 in 1983.

Revenues

Electric revenues increased at an annual rate of 13 percent between 1979 and 1983 because of increases in rates and kilowatt-hour sales. Rate increases were necessitated by the effects of increased operating expenses, recovery of the cost of canceled construction projects and the inclusion of construction work in progress (CWIP) and McGuire Unit 1 in rate base. Kilowatt-hour sales increased by an average of 2 percent annually. Sales in 1983 were 5.4 percent higher than in 1982, primarily because of the improved economy and unusually hot summer weather.

Operating Expenses

During the 1979-1983 period, the most significant increase in electric expenses was in non-fuel operating and maintenance, which rose at an annual rate of 18 percent. This increase was primarily attributable to McGuire Unit 1 beginning commercial operation in 1981, requirements by the Nuclear Regulatory Commission and inflation. (See "Selected Financial Data—Effects of Changing Prices.") Fuel and purchased power expenses increased at an annual rate of 6 percent over the five-year period. From 1979-1981, fuel expense rose because the unit price of fuel increased while the generation mix remained relatively constant. In 1982, lower levels of generation reflected the decline in the economy, thus reducing fuel expense. As a result of improved nuclear and hydroelectric generation, fuel expense continued to decline in 1983, even though total generation rose 7.5 percent over the prior year.

Other

Allowance for funds used during construction (ADC) increased during the 1979-1981 period as a result of higher construction work in progress and embedded cost of funds. However, in 1982 and 1983, ADC decreased because McGuire Unit 1 began commercial operation, additional CWIP was included in rate base and several nuclear projects were canceled. Since 1979, interest deductions and dividends on preferred and preference stocks have increased at annual rates of 10 percent and 4 percent, respectively. These increases are due to higher financing rates and the issuance of additional securities.

The assets of Eastover Mining Company and the related land leased from Eastover Land Company were sold in 1983. A provision for loss of $30 million was recorded in 1982 (after the effect of income tax benefits of $28 million).

Capital Needs

Since January 1, 1979, additions to property of $3.9 billion (including nuclear fuel) and retirements of $1.1 billion have resulted in a net increase in gross plant of $2.8 billion. During 1983, additions to property of $680 million (including nuclear fuel) and retirements of $598 million resulted in a net increase in gross plant of $82 million. Retirements were unusually large because of the sale of a portion of the Catawba Nuclear Station in 1981 and the cancellation of the Perkins and Cherokee nuclear projects during 1982 and 1983. (See Notes 3 and 5 in Notes to Financial Statements.)

Expenditures for construction of major generating facilities and for nuclear fuel constituted approximately 78 percent of the Company's capital requirements during the past five years. Additional funds were required for transmission and distribution facilities, the refunding of maturing securities and sinking funds, and increased working capital.

Projected construction and nuclear fuel costs are $2.1 billion for the three-year period 1984 through 1986, excluding costs related to the portions of the Catawba Nuclear Station that have been sold. Major plant construction costs should constitute a lower percentage of the Company's capital requirements for the next three years. Construction plans continue to reflect a lower projected growth rate of peak load, which is due in part to the Company's comprehensive load management program and energy conservation.

The construction program includes plans for three nuclear units to begin commercial operation within the next four years. Commercial operation of McGuire Unit 2 is scheduled for early 1984. Total estimated costs, including initial core nuclear fuel, for both units of McGuire are $2.2 billion. The Company's portion of the total estimated construction and initial core nuclear fuel costs for both units of Catawba is $1.0 billion, including $654 million spent as of December 31, 1983. Commercial operation of Catawba Units 1 and 2 is scheduled for 1985 and 1987, respectively. Construction of this station is currently ahead of schedule.

Liquidity and Resources

Improvements in several key financial indicators were largely attributable to improved earnings and the cancellation of major construction projects. During 1983, internal cash generation, including the tax effects of the Cherokee cancellation, amounted to 83 percent, exceeding the Company's goal of 50 percent. From 1979 to 1982, funds from operations provided approximately 33 percent of the Company's capital requirements. As a result of an improved financial position, the Company has approximately $126 million in short-term investments at year-end. The Company prefers to limit short-term debt to about $150 million and currently maintains bank lines of credit of $385 million. The appropriate amount of such lines of credit is under reconsideration.

Additional funds were obtained during the 1979-1983 period from the sales of $788 million in first and refunding mortgage bonds, $137 million in preferred stock, and $557 million in common stock, including the non-cash exchange for bonds in January 1982. (See Note 4 in Notes to Financial Statements.) The Company also obtained $521 million from the 1981 sale of a portion of the Catawba Nuclear Station, eliminating the need for external financing in that year. In June 1983, the Company borrowed the proceeds of the sale of $102 million principal amount of pollution control revenue bonds issued by Oconee County, S.C. As of December 31, 1983, the Company had received approximately $46 million in proceeds, with the remainder to be received over the next three years as expenditures are incurred. Further significant long-term public financings are not anticipated in the near future.

As of December 31, 1983, the capital structure was 45 percent long-term debt, 12 percent preferred stock and 43 percent common equity. This structure is consistent with the Company's financial goals.

As a result of higher earnings, 1983 fixed-charges coverage, using the Securities and Exchange Commission method, increased to 3.46 times, representing significant progress toward meeting the Company's goal of 3.5 times. For 1979 through 1982, actual coverage did not change significantly because higher earnings were offset by increasing costs of debt.

From 1979 through 1982, the market price of the Company's common stock averaged 85 percent of book value. During 1983, the market-to-book ratio improved, generally exceeding 90 percent. In 1983, the Company implemented a plan to purchase common stock on the open market to satisfy the requirements of the Employees' Stock Ownership Plan and authorized open-market purchases, which began in 1984, for the Stock Purchase-Savings Program for Employees. Utilizing open-market purchases for these two plans will reduce the need to issue additional common stock, thereby minimizing revenue requirements and the dilution of earnings and common stock equity.

During the past five years, the Company has been granted retail rate increases allowing approximately 58 percent of the requested additional revenues. As of December 31, 1983, the Company had rate requests pending in each of its three regulatory jurisdictions. These requests seek recovery of the Company's investment in McGuire Unit 2, a higher rate of return on common equity and increased operating expenses. The Company's requests in its South Carolina and wholesale jurisdictions also include Cherokee cancellation costs not previously reflected in rates. (For rate information by jurisdiction, see Notes 2 and 3 in Notes to Financial Statements.)

In the North Carolina jurisdiction, the Company requested permission to implement an interim rate increase in conjunction with the commercial operation of McGuire Unit 2, scheduled for early 1984. The Commission denied the Company's request, but ruled instead that the costs associated with the unit allocated to the North Carolina retail jurisdiction, must be deferred until a rate order is issued on the entire case.

Certain of the Company's wholesale customers purchased ownership interests in the Catawba Nuclear Station in prior years. In accordance with these purchase agreements, in 1983 the buyers began supplying electricity to their members—municipalities and cooperatives that formerly were customers of the Company.

While 1983 was a year of significant financial achievement, the Company's ability to maintain its level of financial strength will be dependent upon many factors. Significant factors in the Company's immediate financial future include adequate and timely rate relief, reliable nuclear plant performance, increased kilowatt-hour sales, and continued economic improvement in the Piedmont Carolinas.

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Item 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company were prepared by management which is responsible for their integrity and objectivity. The statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions that should be included. The other information in the annual report is consistent with the financial statements. In preparing the financial statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. The Company's accounting controls provide reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected by employees within a timely period in the normal course of performing their assigned functions. The Company's accounting controls are continually reviewed for effectiveness and are augmented by written policies, standards and procedures, and a strong program of internal audit.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, composed solely of directors who are not officers or employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each and to monitor the discharge by each of their responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte Haskins & Sells, who have free access to the audit committee or the Board of Directors, without management present, to discuss internal accounting control, auditing and financial reporting matters.

AUDITORS' OPINION

DUKE POWER COMPANY:

We have examined the financial statements and supplemental schedules of Duke Power Company listed in the accompanying index on page 22. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our report dated February 18, 1983, our opinion on the 1982 and 1981 financial statements referred to above was qualified as being subject to the effects of such adjustments, if any, as might have been required if the outcome of the uncertainty concerning regulatory approval to recover the costs associated with the cancellation of certain nuclear generating units had been known. As described in Note 3, during 1983 the Company received approval to recover the costs of these canceled units allocated to its North Carolina retail jurisdiction and similar recovery has been permitted in South Carolina with respect to the costs of two units of the canceled station. As a result, recovery of costs related to the canceled nuclear station appears to be reasonably assured. Accordingly, our present opinion on the 1982 and 1981 financial statements, as expressed herein, is different from that expressed in our previous report.

In our opinion, the financial statements referred to above present fairly the financial position of the Company at December 31, 1983 and 1982 and the results of its operations and the source of its funds for plant construction costs for each of the three years in the period ended December 31, 1983, in conformity with generally accepted accounting principles applied on a consistent basis. Also, in our opinion, the supplemental schedules, when considered in relation to the basic financial statements, present fairly in all material respects the information shown therein.

DELOITTE HASKINS & SELLS

Charlotte, North Carolina
February 17, 1984

DUKE POWER COMPANY

STATEMENTS OF INCOME

	Year Ended December 31		
	1983	1982	1981
	(Dollars in thousands)		
ELECTRIC REVENUES (Notes 1 and 2)	$2,420,252	$2,244,480	$1,908,454
ELECTRIC EXPENSES			
Operation			
Fuel used in electric generation (Note 1)	739,829	781,406	790,967
Net interchange and purchased power (credit)	(19,819)	(10,685)	25,068
Wages, benefits and materials	350,162	329,954	264,488
Maintenance of plant facilities	187,267	177,766	131,670
Depreciation and amortization (Notes 1 and 3)	209,750	186,080	142,899
General taxes	173,826	158,289	139,140
Income taxes (Notes 1 and 12)	330,023	231,902	137,872
Total electric expenses	1,971,038	1,854,712	1,632,104
Electric operating income	449,214	389,768	276,350
OTHER INCOME (Notes 1, 5 and 12)			
Allowance for equity funds used during construction	144,048	146,214	159,285
Earnings of subsidiaries, net	10,415	7,039	14,662
Provision for loss on disposal of assets	—	(30,000)	—
Other, net	5,391	12,548	28,791
Income taxes—other, net (deduction)	(3,037)	(11,687)	(9,442)
Income taxes—credit	56,184	50,934	60,747
Total other income	213,001	175,048	254,043
Income before interest deductions	662,215	564,816	530,393
INTEREST DEDUCTIONS			
Interest on long-term debt	272,349	254,643	245,070
Other interest	6,766	12,802	11,694
Allowance for borrowed funds used during construction (credit) (Note 1)	(48,177)	(52,506)	(62,622)
Total interest deductions	230,938	214,939	194,142
Income before extraordinary item	431,277	349,877	336,251
EXTRAORDINARY ITEM (Note 4)	—	48,304	—
NET INCOME	431,277	398,181	336,251
Dividends on preferred and preference stocks	62,600	62,164	57,895
EARNINGS FOR COMMON STOCK	$ 368,677	$ 336,017	$ 278,356
COMMON STOCK DATA			
Average shares outstanding (thousands)	97,784	93,679	87,313
Earnings before extraordinary item	$3.77	$3.07	$3.19
Extraordinary item	—	0.52	—
Earnings per share	$3.77	$3.59	$3.19
Dividends per share	$2.32	$2.24	$2.08

See Notes to Financial Statements.

DUKE POWER COMPANY

STATEMENTS OF SOURCE OF FUNDS FOR
PLANT CONSTRUCTION COSTS

	Year Ended December 31		
	1983	1982	1981
	(Dollars in thousands)		
FUNDS FROM OPERATIONS			
Income before non-fund extraordinary item	$431,277	$349,877	$336,251
Non-fund items			
Depreciation and amortization (Notes 1 and 3)	324,608	268,651	224,675
Deferred income taxes and investment tax credit, net of amortization (Note 12)	333,045	159,515	109,572
Equity component of the allowance for funds used during construction	(144,048)	(146,214)	(159,285)
Other, net	(6,073)	25,171	(13,146)
Funds from operations	938,809	657,000	498,067
Dividends paid	(289,564)	(272,115)	(239,598)
Funds retained in the business	649,245	384,885	258,469
FUNDS FROM FINANCINGS AND SALE OF ASSETS—NET PROCEEDS			
Common stock (Note 4)	84,326	199,134	35,954
Pollution control series	45,648	—	—
Nuclear fuel trusts	60,645	33,052	42,248
Term notes	—	79,721	—
First mortgage bonds	—	221,521	—
Preferred stock	—	38,296	—
Sale of an interest in the Catawba Nuclear Station (Note 5)	—	—	520,562
Decrease in notes payable	(57,210)	(114,140)	(25,650)
Funds from financings and sale of assets	133,409	457,584	573,114
Total available funds	782,654	842,469	831,583
INCREASE IN WORKING CAPITAL	(165,879)	(58,068)	(92,946)
LONG-TERM DEBT RETIRED/PREFERRED STOCKS REACQUIRED (Note 4)	(81,097)	(194,555)	(93,551)
PLANT CONSTRUCTION EXPENDITURES	535,678	589,846	645,086
EQUITY COMPONENT OF THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	144,048	146,214	159,285
PLANT CONSTRUCTION COSTS	$679,726	$736,060	$804,371
SUMMARY OF PLANT CONSTRUCTION COSTS			
Production	$376,134	$405,329	$504,292
Transmission	32,022	40,599	36,233
Distribution	127,989	113,881	112,073
General	38,966	23,895	22,557
Subtotal	575,111	583,704	675,155
Nuclear fuel	104,615	152,356	129,216
PLANT CONSTRUCTION COSTS	$679,726	$736,060	$804,371

See Notes to Financial Statements.

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DUKE POWER COMPANY

BALANCE SHEETS

ASSETS

	December 31	
	1983	1982
	(Dollars in thousands)	
ELECTRIC PLANT		
(At original cost—Notes 1, 3, 10 and 13)		
Electric plant in service	$6,270,799	$5,940,941
Less accumulated depreciation and amortization	2,405,150	2,106,427
Electric plant in service, net	3,865,649	3,834,514
Construction work in progress	2,296,843	2,551,177
Total electric plant, net	6,162,492	6,385,691
OTHER PROPERTY AND INVESTMENTS		
Other property—at cost (less accumulated depreciation: 1983—$8,022; 1982—$7,384)	34,773	28,675
Investments in and advances to subsidiaries (Note 1)	61,808	75,430
Other investments—at cost or less	29,317	24,900
Total other property and investments	125,898	129,005
CURRENT ASSETS		
Cash (Note 6)	596	4,053
Short-term investments	125,590	—
Receivables (less allowance for losses: 1983—$3,982; 1982—$3,983)	232,577	162,671
Refundable income taxes (Note 12)	41,209	—
Materials and supplies—at average cost		
Coal	138,217	179,987
Other	105,735	98,815
Prepayments	10,316	8,841
Total current assets	654,240	454,367
DEFERRED DEBITS		
Debt expense, being amortized over terms of related debt	4,045	4,961
Canceled construction projects (Notes 3 and 12)	414,633	77,794
Other	18,137	5,962
Total deferred debits	436,815	88,717
TOTAL ASSETS	$7,379,445	$7,057,780

See Notes to Financial Statements.

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