FORM 8-K

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GEORGIA POWER CO

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Business Address
333 PIEDMONT AVE NE
ATLANTA GA 30308
4045266526

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SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) February 16, 1994

GEORGIA POWER COMPANY

(Exact name of registrant as specified in its charter)

Georgia	1-6468	58-0257110
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Piedmont Avenue, N.E., Atlanta, Georgia	30308
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (404) 526-6526

N/A

(Former name or former address, if changed since last report.)

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Item 7. Financial Statements, Pro Forma Financial Information and Exhibits.

<TABLE>

<S>	<C>		<C>
(c)	Exhibits.		
	23	-	Consent of Arthur Andersen & Co.
	99	-	Audited Financial Statements of Georgia Power Company as of December 31, 1993.

</TABLE>

SIGNATURE

Pursuant to the requirements 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.

GEORGIA POWER COMPANY

By /s/ Wayne Boston

Wayne Boston
Assistant Secretary

Date: March 1, 1994

EXHIBIT 23

ARTHUR ANDERSEN & CO.

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated February 16, 1994, included in this Form 8-K, into Georgia Power Company's previously filed Registration Statement File No. 33-49661.

/s/ Arthur Andersen & Co.

ARTHUR ANDERSEN & CO.

Atlanta, Georgia
March 1, 1994

EXHIBIT 99

MANAGEMENT'S REPORT
Georgia Power Company 1993 Annual Report

The management of Georgia Power Company has prepared this annual report and is responsible for the financial statements and related information. These statements were prepared in accordance with generally accepted accounting principles appropriate in the circumstances, and necessarily include amounts that are based on the best estimates and judgments of management. Financial information throughout this annual report is consistent with the financial statements.

The Company maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded and that the books and records reflect only authorized transactions of the Company. Limitations exist in any system of internal controls based upon the recognition that the cost of the system should not exceed its benefits. The Company believes that its system of internal accounting controls maintains an appropriate cost/benefit relationship.

The Company's system of internal accounting controls is evaluated on an ongoing basis by the Company's internal audit staff. The Company's independent public accountants also consider certain elements of the internal control system in order to determine their auditing procedures for the purpose of expressing an opinion on the financial statements.

The audit committee of the board of directors, which is composed of five directors who are not employees, provides a broad overview of management's financial reporting and control functions. At least three times a year this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal control and financial reporting matters. The internal auditors and the independent public accountants have access to the members of the audit committee at any time.

Management believes that its policies and procedures provide reasonable assurance that the Company's operations are conducted with a high standard of business ethics.

In management's opinion, the financial statements present fairly the financial position, results of operations and cash flows of Georgia Power Company in conformity with generally accepted accounting principles. As discussed in Note 4 to the financial statements, an uncertainty exists with respect to the actions of regulators regarding recoverability of the Company's investment in the Rocky Mountain pumped storage hydroelectric project. The outcome of this uncertainty cannot be determined until regulatory proceedings are concluded. Accordingly, no provision for any write-down of the costs associated with the Rocky Mountain project resulting from the potential actions of the Georgia Public Service Commission has been made in the accompanying financial statements.

/s/ H. Allen Franklin	/s/ Warren Y. Jobe
H. Allen Franklin	Warren Y. Jobe
President and Chief Executive Officer	Executive Vice President, Treasurer and Chief Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS
Georgia Power Company 1993 Annual Report

TO THE BOARD OF DIRECTORS
OF GEORGIA POWER COMPANY:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (a Georgia corporation) as of December 31, 1993 and 1992, and the related statements of income, retained earnings, paid-in capital, and cash flows for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the

Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements (pages 10-30) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 1993 and 1992, and the results of its operations and its cash flows for the periods stated, in conformity with generally accepted accounting principles.

As explained in Notes 2 and 7 to the financial statements, effective January 1, 1993, the Company changed its methods of accounting for postretirement benefits other than pensions and for income taxes.

As more fully discussed in Note 4 to the financial statements, an uncertainty exists with respect to the actions of the regulators regarding the recoverability of the Company's investment in the Rocky Mountain pumped storage hydroelectric project. The outcome of this uncertainty cannot be determined until regulatory proceedings are concluded. Accordingly, no provision for any write-down of the costs associated with the Rocky Mountain project resulting from the potential actions of the Georgia Public Service Commission has been made in the accompanying financial statements.

/s/ Arthur Andersen & Co.

Atlanta, Georgia
February 16, 1994

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION
Georgia Power Company 1993 Annual Report

RESULTS OF OPERATIONS

EARNINGS

Georgia Power Company's 1993 earnings totaled $570 million, representing a $49 million (9.5 percent) increase over the prior year. This improvement is primarily a result of higher retail revenues and lower financing costs. Also, during the period, the Company had an $18 million after-tax gain on the sale of a portion of Plant Scherer Unit 4. Higher retail revenues reflect growth in energy sales of 6.1 percent from 1992 levels primarily due to exceptionally hot summer weather during 1993. Interest expense and preferred stock dividends decreased in 1993 due to the redemption and refinancing of higher-cost debt and preferred stock. These positive events were partially offset by higher operating expenses.

In comparing 1992 earnings to the prior year, it should be noted that 1991 earnings included two unusual items that significantly affect this comparison. Earnings in 1991 were $89 million higher due to the completion of a settlement agreement with Gulf States Utilities Company (Gulf States) related to power sales contracts. This increase was partially offset by an after-tax charge of $33 million in 1991 for a work force reduction program. A comparison of 1992 to 1991 -- excluding these unusual items -- would reflect a 1992 increase in earnings of $102 million.

REVENUES

The following table summarizes the factors impacting operating revenues for the 1991-1993 period:

<TABLE>

	Increase (Decrease) From Prior Year		
	1993	1992	1991

		(in millions)	
<S>	<C>	<C>	<C>
Retail -			
Change in base rates	$ -	$ 95	$ 27
Sales growth	45	76	67
Weather	126	(58)	(16)
Fuel cost recovery	76	(26)	(54)
Demand-side option programs	15	-	-
Total retail	262	87	24
Sales for resale -			
Non-affiliates	(106)	(96)	(47)
Affiliates	(6)	2	(103)
Total sales for resale	(112)	(94)	(150)
Other operating revenues	4	3	(18)
Total operating revenues	$ 154	$ (4)	$ (144)
Percent change	3.6%	(0.1)%	(3.2)%

</TABLE>

Retail revenues of $3.8 billion in 1993 increased $262 million (7.4 percent) over the prior year, compared with an increase of $87 million (2.5 percent) in 1992. The exceptionally hot weather during the summer of 1993 was the primary factor affecting the increase in retail revenues over 1992. The increase in retail revenues for 1992 was a result of higher retail rates and sales growth, partially offset by mild weather and lower fuel revenues. Fuel revenues generally represent the direct recovery of fuel expense, including the fuel component of purchased energy, and do not affect net income. Revenues from demand-side options programs generally represent the direct recovery of program costs. See Note 3 to the financial statements for further information on these programs.

Revenues from sales to non-affiliated utilities decreased in both 1993 and 1992. Contractual unit power sales to Florida utilities for 1993 and 1992 are down compared with prior years, primarily due to scheduled reductions that corresponded with the sales to these utilities of portions of Plant Scherer Unit 4 in July 1991 and June

1993. Sales to municipalities and cooperatives increased slightly in 1993 due to the hot summer weather. Generally, these sales have been decreasing as these customers retain more of their own generation at facilities jointly owned with the Company.

Revenues from sales to non-affiliated utilities outside the service area under long-term contracts consist of capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components were as follows:

<TABLE>
<CAPTION>

	1993	1992	1991
		(in millions)	
<S>	<C>	<C>	<C>
Capacity	$152	$233	$274
Energy	113	168	204
Total	$265	$401	$478

</TABLE>

Revenues from sales to affiliated companies within the Southern electric system will vary from year to year depending on demand and the availability and cost of generating resources at each company. Sales to affiliated companies do not have a significant impact on earnings.

Changes in revenues are a function of the amount of energy sold each year. Kilowatt-hour (KWH) sales for 1993 and the percent change by year were as follows:

<TABLE>

<CAPTION>

	1993 KWH (in billions)	Percent Change 1993	1992	1991
<S>	<C>	<C>	<C>	<C>
Residential	16.7	11.5%	0.8%	0.3%
Commercial	18.3	5.9	2.2	1.6
Industrial	23.6	2.9	3.1	0.8
Other	0.5	5.7	1.7	0.1
Total retail	59.1	6.1	2.2	0.9
Sales for resale -				
Non-affiliates	14.3	(9.8)	(15.2)	(7.1)
Affiliates	3.0	(8.8)	(14.6)	(53.0)
Total sales for resale	17.3	(9.7)	(15.1)	(20.5)
Total sales	76.4	2.1	(2.9)	(6.5)

</TABLE>

The hot summer weather during 1993 contributed primarily to the sales growth in the residential and commercial classes. Continued improvement in economic conditions positively impacted sales growth in the commercial and industrial classes. Residential energy sales growth in 1992 reflected mild weather. Commercial and industrial sales growth in 1992 is attributable to improved economic conditions.

The decrease in energy sales to non-affiliated utilities reflects scheduled reductions in contractual power sales.

EXPENSES

Fuel expense increased 2.3 percent in 1993 due to higher generation, which was partially offset by lower nuclear fuel costs. In 1992, fuel expense decreased 6.9 percent due to lower generation and lower fuel costs. Purchased power expense has decreased significantly since 1991, reflecting declining contractual capacity purchases from the co-owners of plants Vogtle and Scherer. Purchased power expense decreased $88 million in 1993 and $43 million in 1992. The declines in Plant Vogtle contractual capacity purchases did not have a significant impact on earnings in 1993 or 1992 as these costs are being levelized over six years under the terms of the 1991 Georgia Public Service Commission (GPSC) retail rate order. The levelization is reflected in the amortization of deferred Plant Vogtle expenses in the income statements. See Note 3 to the financial statements for additional information.

Other Operation and Maintenance (O & M) expenses increased 9.0 percent in 1993 after remaining relatively flat in 1992. The increase in 1993 is primarily the result of environmental remediation costs at various current and former operating sites, the one- time costs of an automotive fleet reduction program and the recognition of higher employee benefit costs under new accounting rules adopted in 1993. See Note 2 to the financial statements for additional information concerning these new rules. Also, during 1993, O & M expenses reflect costs associated with new demand-side option programs. These costs were offset by increases in retail revenues. See Note 3 to the financial statements for additional information on the recovery of demand-side option program costs.

Depreciation and amortization expense increased slightly due to additional plant investment. The 1992 decrease is due to the effects of lower depreciation rates effective in October 1991. Taxes other than income taxes increased 7.4 percent in 1993 and 3.8 percent in 1992.

These increases reflect higher ad valorem taxes. The 1993 increase also includes higher taxes paid to municipalities as a result of increased sales.

Income tax expense increased $62 million in 1993 due primarily to higher earnings and the effect of a one percent increase in the federal tax rate effective January, 1993. Also, the Company incurred $27 million of tax expense in connection with the second in a series of four separate transactions to sell Plant Scherer Unit 4. The sale resulted in an after-tax gain of $18 million.

Interest expense and dividends on preferred stock decreased $19 million (4.0 percent) and $49 million (9.3 percent) in 1993 and 1992, respectively. These reductions are due to significant refinancing of long-term debt and preferred stock. The Company refinanced $1.7 billion of securities in both 1993 and 1992. In addition, the Company has retired $544 million of long-term debt with the proceeds from the 1991 and 1993 Plant Scherer Unit 4 sales. Other interest charges in 1993 include interest related to the settlement of an Internal Revenue Service audit. The settlement, in total, did not have an effect on 1993 net income.

The Company has deferred certain expenses and recorded a deferred return related to Plant Vogtle under phase-in plans. See Note 3 to the financial statements under "Plant Vogtle Phase-In-Plans" for information regarding the deferral and subsequent amortization of costs related to Plant Vogtle.

EFFECTS OF INFLATION

The Company is subject to rate regulation and income tax laws that are based on the recovery of historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in long-lived utility plant. Conventional accounting for historical cost does not recognize either this economic loss or the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt and preferred stock. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed.

FUTURE EARNINGS POTENTIAL

The results of operations for the past three years are not necessarily indicative of future earnings. The level of future earnings depends on numerous factors ranging from growth in energy sales to regulatory matters.

Growth in energy sales is subject to a number of factors which traditionally have included changes in contracts with neighboring utilities, energy conservation practiced by customers, the elasticity of demand, weather, competition, and the rate of economic growth in the Company's service area. Assuming normal weather, retail sales growth is projected to be approximately 2 percent annually on average during 1994 through 1996.

The scheduled addition of four combustion turbine generating units in 1994, four units in 1995 and one unit in 1996, as well as the Rocky Mountain pumped storage hydroelectric project in 1995, will increase related O & M and depreciation expenses. See Note 4 to the financial statements for information on regulatory uncertainties related to the Rocky Mountain project. The GPSC has certified the construction of the 1994 and 1995 combustion turbine generating units for meeting peak generating needs. In addition, the Company has completed a demonstration competitive bidding process for its supply-side requirements expected for 1996. The Company has filed with the GPSC for certification of a four-year purchase power agreement beginning in 1996, and for construction of a jointly owned combustion turbine to be completed in 1996 to meet these needs.

As part of efforts to curtail growth in operating expenses, the Company is reducing its work force through an early-retirement program announced in January 1994. The program resulted in a first quarter 1994 after-tax charge to earnings of $39 million. The program has an expected payback period of approximately two years.

Pursuant to an Integrated Resource Plan approved by the GPSC in 1992, the Company has implemented various demand-side option programs and has been authorized by the GPSC to recover associated program costs through rate riders. On October 15, 1993, a superior court judge ruled that recovery of these costs through rate riders is unlawful. The Company has ceased collection of the rate riders and is deferring program costs as ordered by the

GPSC pending the final outcome of this matter. See Note 3 to the financial statements for additional information.

The Company has completed two in a series of four separate transactions to sell Unit 4 of Plant Scherer to two Florida utilities. The remaining transactions are scheduled to take place in 1994 and 1995. If the sales take place as planned, the Company would realize an additional after-tax gain estimated to total approximately $20 million. See Note 5 to the financial statements for additional information.

Compliance costs related to the Clean Air Act Amendments of 1990 (Clean Air Act) could reduce earnings if such costs cannot be billed to customers. The Clean Air Act is discussed later under "Environmental Issues."

The Energy Policy Act of 1992 (Energy Act) will have a profound effect on the future of the electric utility industry. The Energy Act promotes energy efficiency, alternative fuel use, and increased competition among electric utilities. The law also includes provisions to streamline the licensing process for new nuclear generating plants. The Energy Act marks the beginning of a major change in the traditional business practices of selling electricity. The Energy Act allows Independent Power Producers (IPPs) and other electric suppliers access to a utility's transmission lines to sell their electricity to other utilities. This may enhance the incentives for IPPs to build cogeneration plants for the Company's large industrial and commercial customers. If the Company does not remain a low cost producer and provide quality service, the Company's sales growth could be limited and this could significantly erode earnings.

The Company continues to compete with other electric suppliers within the state. In Georgia, most new retail customers with more than 900 kilowatts of connected load may choose their electricity supplier. In addition, the bulk power market has become very competitive as utilities, IPPs and cogenerators seek to supply future capacity needs. Competition can create new business opportunities, but it increases risk and has the potential to adversely affect earnings.

The Federal Energy Regulatory Commission (FERC) regulates wholesale rate schedules and power sales contracts that the Company has with its sales for resale customers. The FERC currently is reviewing the rate of return on common equity included in these schedules and contracts and may require such returns to be lowered, possibly retroactively. See Note 3 to the financial statements under "FERC Review of Equity Returns" for additional information.

NEW ACCOUNTING STANDARDS

The Financial Accounting Standards Board (FASB) issued Statement No. 112, Employers' Accounting for Postemployment Benefits, which must be adopted by 1994. The new standard requires that all types of benefits provided to former or inactive employees and their families prior to retirement be accounted for on an accrual basis. These benefits include salary continuation, severance pay, supplemental unemployment benefits, disability-related benefits, job training, and health and life insurance coverage. In 1993, the Company adopted Statement No. 112, with no material effect on the financial statements.

The FASB has issued Statement No. 115, Accounting for Certain Investments in Debt and Equity Securities, which will be effective in 1994. Statement No. 115 supersedes FASB Statement No. 12, Accounting for Certain Marketable Securities. The Company adopted the new rules in January, 1994, with no material effect on the financial statements.

FINANCIAL CONDITION

OVERVIEW

The principal changes in the Company's financial condition in 1993 were gross utility plant additions of $674 million and the lowering of the cost of capital achieved through the refinancing or retirement of $1.7 billion of long-term debt and preferred stock.

On January 1, 1993, the Company changed its methods of accounting for postretirement benefits other than pensions and for income taxes. See Notes 2 and 7 to the financial statements regarding the impact of these changes.

The funds needed for gross property additions are currently provided from operations. The Statements of Cash Flows provide additional details.

FINANCING ACTIVITIES

In 1993, the Company continued to lower its financing costs by issuing new securities and other debt, and retiring or repaying high-cost issues. New issues during 1991 through 1993 totaled $3.0 billion and retirement or repayment of securities totaled $4.2 billion. The retirements included the redemption of $253 million and $291 million in 1993 and 1991, respectively, of first mortgage bonds with the proceeds from the Plant Scherer Unit 4 sales. Composite financing rates for the years 1991 through 1993, as of year-end, were as follows:

	1993	1992	1991
Composite interest rate on long-term debt	7.86%	8.49%	9.05%
Composite preferred stock dividend rate	6.76%	7.52%	7.99%

The Company's current securities ratings are as follows:

	Duff & Phelps	Moody's	Standard & Poor's
First Mortgage Bonds	A+	A3	A-
Preferred Stock	A-	baa1	BBB+
Unsecured Bonds	A	Baa1	BBB+
Commercial Paper	*	P2	A2

* Not rated by Duff & Phelps

LIQUIDITY AND CAPITAL REQUIREMENTS

Cash provided from operations increased by $236 million in 1993, primarily due to higher retail sales, lower interest costs, decreasing capacity purchases from the co-owners of plants Vogtle and Scherer and the receipt of cash payments from Gulf States that completed the settlement of litigation.

The Company estimates that construction expenditures for the years 1994 through 1996 will total $688 million, $555 million and $629 million, respectively. The Company will continue to invest in transmission and distribution facilities and enhance existing generating plants. These expenditures also include amounts for nine combustion turbine generating units and equipment that will be required to comply with the provisions of the Clean Air Act.

The Company's contractual capacity purchases will decline by $113 million over the next three years. Cash requirements for sinking fund requirements, redemptions announced, and maturities of long-term debt are expected to total $377 million during 1994 through 1996.

As a result of requirements by the Nuclear Regulatory Commission, the Company has established external sinking funds for the purpose of funding nuclear decommissioning costs. For 1994 through 1996, the amount to be funded for the Company totals $16 million annually. For additional information concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Nuclear Decommissioning."

SOURCES OF CAPITAL

The Company expects to meet future capital requirements primarily using funds generated from operations and, if needed, by the issuance of new debt and equity securities, term loans, and short-term borrowings. To meet short-term cash needs and contingencies, the Company had approximately $540 million of unused credit arrangements with banks at the beginning of 1994. See Note 8 to the financial statements for additional information.

Completing the remaining two transactions for the sale of Plant Scherer Unit 4 will generate approximately $130 million in both 1994 and in 1995.

The Company is required to meet certain coverage requirements specified in its mortgage indenture and corporate charter to issue new first mortgage bonds and preferred stock. The Company's ability to satisfy all coverage requirements is such that it could issue new first mortgage bonds and preferred stock to provide sufficient funds for all anticipated requirements.

ENVIRONMENTAL ISSUES

In November 1990, the Clean Air Act was signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- will have a significant impact on The Southern Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants will be required in two phases. Phase I compliance must be implemented in 1995 and affects eight generating plants -- some 10,000 megawatts of capacity or 35 percent of total capacity -- in the Southern electric system. Phase II compliance is required in 2000, and all fossil-fired generating plants in the Southern electric system will be affected.

Beginning in 1995, the Environmental Protection Agency (EPA) will allocate annual sulfur dioxide emission allowances through the newly established allowance trading program. An emission allowance is the authority to emit one ton of sulfur dioxide during a calendar year. The method for allocating allowances is based on the fossil fuel consumed from 1985 through 1987 for each affected generating unit. Emission allowances are transferable and can be bought, sold, or banked and used in the future.

The sulfur dioxide emission allowance program is expected to minimize the cost of compliance. The market for emission allowances is developing slower than expected. However, The Southern Company's sulfur dioxide compliance strategy is designed to take advantage of allowances as the market develops.

The Southern Company expects to achieve Phase I sulfur dioxide compliance at the eight affected plants by switching to low-sulfur coal, and this has required some equipment upgrades. This compliance strategy is expected to result in unused emission allowances being banked for later use. Additional construction expenditures are required to install equipment for the control of nitrogen oxide emissions at these eight plants. Also, continuous emissions monitoring equipment would be installed on all fossil-fired units. Under this Phase I compliance approach, Georgia Power's construction expenditures are estimated to total approximately $150 million through 1995.

Phase II compliance costs are expected to be higher because requirements are stricter and all fossil-fired generating plants are affected. For sulfur dioxide compliance, The Southern Company could use emission allowances banked during Phase I, increase fuel switching, install flue gas desulfurization equipment at selected plants, and/or purchase more allowances depending on the price and availability of allowances. Also, in Phase II, equipment to control nitrogen oxide emissions will be installed on additional system fossil-fired plants as required to meet anticipated Phase II limits. Therefore, during the period 1996 to 2000, compliance could require total Georgia Power construction expenditures ranging from approximately $150 million to $325 million. However, the full impact of Phase II compliance cannot now be determined with certainty, pending the development of a market for emission allowances, the completion of EPA regulations, and the possibility of new emission reduction technologies.

An increase of up to 2 percent in Georgia Power's annual revenue requirements from customers could be necessary to fully recover the cost of compliance for both Phase I and Phase II of the Clean Air Act. Compliance costs include construction expenditures, increased costs for switching to low-sulfur coal, and costs related to emission allowances. There can be no assurance that all Clean Air Act costs will be recovered.

Metropolitan Atlanta is classified as a non-attainment area with regard to the ozone ambient air quality standards. Title I of the Clean Air Act requires the state of Georgia to conduct specific studies and establish new control rules by November 1994 -- affecting sources of nitrogen oxides and volatile organic compounds -- to achieve attainment by 1999. As the required first step, the state has issued rules for the application of reasonably available control technology to reduce nitrogen oxide emissions by May 31, 1995. The results of these new rules require nitrogen oxide controls, above Title IV requirements, on some Company plants. Final attainment rules, based on modeling studies, could require installation of additional controls for nitrogen oxide emissions as early as 1997. Compliance with any new rules could result in significant additional costs. The impact of new rules will depend on the development and implementation of such rules.

Title III of the Clean Air Act requires a multi-year EPA study of power plant emissions of hazardous air pollutants. The study will serve as the basis for a decision on whether additional regulatory control of these substances is warranted. Compliance with any new control standards could result in significant additional costs. The impact of new standards -- if any -- will depend on the development and implementation of applicable regulations.

The EPA continues to evaluate the need for a new short-term ambient air quality standard for sulfur dioxide. Preliminary results from an EPA study on the impact of a new standard indicate that a number of plants could be required to install sulfur dioxide controls. These controls would be in addition to the controls already required to meet the acid rain provision of the Clean Air Act. The EPA is expected to take some action on this issue in 1994. In addition, the EPA is evaluating the need to revise the ambient air quality standards for particulate matter, nitrogen oxides, and ozone. The impact of any new standards will depend on the level chosen for the standards and cannot be determined at this time.

In 1994 or 1995, the EPA is expected to issue revised rules on air quality control regulations related to stack height requirements of the Clean Air Act. The full impact of the final rules cannot be determined at this time, pending their development and implementation.

In 1993, the EPA issued a ruling confirming the nonhazardous status of coal ash. However, the EPA has until 1998 to classify co-managed utility wastes -- coal ash and other utility wastes -- as either nonhazardous or hazardous. If the EPA classifies the co-managed wastes as hazardous, then substantial additional costs for the management of such wastes may be required. The full impact of any change in the regulatory status will depend on the subsequent development of co-managed waste requirements.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. These laws include the Comprehensive Environmental Response Compensation and Liability Act of 1980 (CERCLA or Superfund). Under these various laws and regulations, the Company could incur costs to clean up properties currently or previously owned. The Company conducts studies to determine the extent of any required clean-up costs and has recognized costs to clean-up known sites in the financial statements.

Several major pieces of environmental legislation are in the process of being reauthorized or amended by Congress. These include: the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; and the Resource Conservation and Recovery Act. Changes to these laws could affect many areas of the Company's operations. The full impact of these requirements cannot be determined at this time, pending the development and implementation of applicable regulations.

Compliance with possible new legislation related to global climate change, electromagnetic fields and other environmental and health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential for lawsuits alleging damages caused by electromagnetic fields exists.

STATEMENTS OF INCOME
For the Years Ended December 31, 1993, 1992, and 1991
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

<S>	<C> 1993	<C> 1992 (in thousands)	<C> 1991
OPERATING REVENUES:			
Revenues (Note 1)	$ 4,389,513	$ 4,229,601	4,235,842
Revenues from affiliates	61,668	67,835	65,586
Total operating revenues	4,451,181	4,297,436	4,301,428
OPERATING EXPENSES:			
Operation --			
Fuel	951,507	929,780	998,701
Purchased power from non-affiliates	313,170	436,761	444,920

Purchased power from affiliates	194,024	158,306	193,114
Provision for separation benefits	-	9,778	52,952
Proceeds from settlement of disputed contracts (Note 3)	-	(4,982)	(142,183)
Other	675,284	616,116	596,565
Maintenance	284,521	264,757	295,012
Depreciation and amortization	379,425	375,460	382,549
Amortization of deferred Plant Vogtle expenses, net (Note 3)	36,284	(30,804)	16,008
Taxes other than income taxes	192,671	179,460	172,893
Federal and state income taxes	452,122	377,542	349,284
Total operating expenses	3,479,008	3,312,174	3,359,815
OPERATING INCOME	972,173	985,262	941,613
OTHER INCOME (EXPENSE):			
Allowance for equity funds used during construction	3,168	5,855	9,083
Income from subsidiary (Note 5)	4,127	4,635	4,576
Deferred return on Plant Vogtle	-	-	34,549
Interest income	3,806	12,475	10,563
Other, net	11,902	(30,527)	13,551
Income taxes applicable to other income	37,661	25,163	(7,522)
INCOME BEFORE INTEREST CHARGES	1,032,837	1,002,863	1,006,413
INTEREST CHARGES:			
Interest on long-term debt	343,634	402,541	459,184
Allowance for debt funds used during construction	(8,271)	(8,310)	(10,385)
Interest on interim obligations	15,530	9,694	4,906
Amortization of debt discount, premium, and expense, net	14,024	8,033	6,214
Other interest charges	47,393	12,425	9,938
Net interest charges	412,310	424,383	469,857
NET INCOME	620,527	578,480	536,556
DIVIDENDS ON PREFERRED STOCK	50,674	57,942	61,701
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$ 569,853	$ 520,538	474,855

</TABLE>
The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 1993 and 1992
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

ASSETS	1993	1992
	(in thousands)	
<S>	<C>	<C>
UTILITY PLANT:		
Plant in service (Note 1)	$ 13,743,521	$ 13,613,361
Less accumulated provision for depreciation	3,822,344	3,569,717
	9,921,177	10,043,644
Nuclear fuel, at amortized cost (Note 1)	135,742	155,194
Construction work in progress (Note 4)	584,013	405,606
Total	10,640,932	10,604,444
Less property-related accumulated deferred income taxes (Note 7)	-	1,589,743
Total	10,640,932	9,014,701
OTHER PROPERTY AND INVESTMENTS:		
Southern Electric Generating Company, at equity (Note 5)	29,201	30,703
Nuclear decommissioning trusts (Note 1)	37,937	20,311
Miscellaneous	31,941	24,760
Total	99,079	75,774

CURRENT ASSETS:		
Cash and cash equivalents	5,896	22,114
Investment securities	-	108,206
Receivables-		
Customer accounts receivable	486,947	357,923
Other accounts and notes receivable	117,249	96,915
Affiliated companies	14,832	22,674
Accumulated provision for uncollectible accounts	(4,300)	(4,121)
Fossil fuel stock, at average cost	111,620	197,332
Materials and supplies, at average cost	287,551	284,272
Prepayments	65,269	91,447
Vacation pay deferred (Note 1)	41,575	40,169
Total	1,126,639	1,216,931
DEFERRED CHARGES:		
Deferred charges related to income taxes (Note 7)	992,510	-
Deferred Plant Vogtle costs (Note 3)	506,980	383,025
Debt expense, being amortized	20,730	17,719
Premium on reacquired debt, being amortized	153,146	116,940
Miscellaneous	196,094	139,352
Total	1,869,460	657,036
TOTAL ASSETS	$ 13,736,110	$ 10,964,442

</TABLE>

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 1993 and 1992
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

CAPITALIZATION AND LIABILITIES	1993	1992
	(in thousands)	
<S>	<C>	<C>
CAPITALIZATION (SEE ACCOMPANYING STATEMENTS):		
Common stock equity	$ 4,045,458	$ 3,888,237
Preferred stock	692,787	692,792
Preferred stock subject to mandatory redemption	-	6,250
Long-term debt	4,031,387	4,131,016
Total	8,769,632	8,718,295
CURRENT LIABILITIES:		
Preferred stock due within one year (Note 8)	-	63,750
Long-term debt due within one year (Note 8)	10,543	95,823
Notes payable to banks (Note 8)	406,700	400,200
Commercial paper (Note 8)	75,527	133,471
Accounts payable-		
Affiliated companies	38,115	33,258
Other	285,929	284,093
Customer deposits	45,922	45,145
Taxes accrued-		
Federal and state income	31,639	43,779
Other	121,854	94,510
Interest accrued	110,497	132,319
Vacation pay accrued	40,060	38,694
Miscellaneous	64,527	89,355
Total	1,231,313	1,454,397
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes (Note 7)	2,479,720	-
Accumulated deferred investment tax credits	478,334	515,539
Disallowed Plant Vogtle capacity buyback costs (Note 5)	63,067	72,201
Deferred credits related to income taxes (Note 7)	452,819	-

Miscellaneous	261,225	204,010
Total	3,735,165	791,750
COMMITMENTS AND CONTINGENT MATTERS (NOTES 2, 3, 4, 5, 6)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 13,736,110	$ 10,964,442

</TABLE>
The accompanying notes are an integral part of these statements.

STATEMENTS OF CAPITALIZATION
AT December 31, 1993 and 1992
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

<S>	1993 (in thousands) <C>	1992 <C>	1993 (percent of total) <C>	1992 <C>
COMMON STOCK EQUITY:				
Common stock, without par value --				
Authorized -- 15,000,000 shares				
Outstanding -- 7,761,500 shares	$ 344,250	$ 344,250		
Paid-in capital	2,384,348	2,384,140		
Premium on preferred stock	413	467		
Retained earnings (Note 8)	1,316,447	1,159,380		
Total common stock equity	4,045,458	3,888,237	46.1 %	44.6 %
CUMULATIVE PREFERRED STOCK, WITHOUT PAR VALUE:				
Authorized -- 55,000,000 shares in 1993;				
52,200,000 shares in 1992				
Outstanding -- 21,027,923 shares in 1993;				
$100 stated value --				
4.60% to 5.64%	95,787	95,792		
6.48% to 7.80%	127,000	127,000		
8.20% to 9.08%	-	25,000		
$25 stated value --				
$1.90 to $2.125	295,000	295,000		
Adjustable rate -- at January 1, 1994:				
4.98%	100,000	-		
5.42%	75,000	-		
6.57%	-	50,000		
7.02%	-	50,000		
7.57%	-	50,000		
Total (annual dividend requirement -- $46,851,000)	692,787	692,792	7.9	7.9
CUMULATIVE PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION, WITHOUT PAR VALUE:				
Authorized and Outstanding -- 2,800,000 shares in 1992				
$25 stated value --				
$2.43	-	45,000		
$2.50	-	25,000		
Total	-	70,000		
Less amount due within one year	-	63,750		
Total excluding amount due within one year	-	6,250	-	0.1

</TABLE>

STATEMENTS OF CAPITALIZATION
At December 31, 1993 and 1992
Georgia Power Company 1993 Annual Report

<TABLE>

<S>		1993 <C>	1992 <C>	1993 <C>	1992 <C>
LONG-TERM DEBT:		(in thousands)		(percent of total)	
First mortgage bonds --					
Maturity	Interest Rates				
October 1, 1994	4 5/8%	-	28,000		
September 1, 1995	4 7/8%	-	36,500		
September 1, 1995	5 1/8%	130,000	130,000		
March 1, 1996	4 3/4%	150,000	-		
July 1, 1996	5 3/4%	-	45,368		
September 1, 1997	6 1/2%	-	50,000		
April 1, 1998	5 1/2%	100,000	-		
September 1, 1998	6 5/8%	-	50,000		
1999 through 2003	6 % to 7 7/8%	820,000	929,500		
2008	6 7/8%	50,000	-		
2016 through 2018	10% to 10 3/4%	69,716	663,170		
2019 through 2023	7.55% to 9.23%	760,000	300,000		
2020	variable rate	-	50,000		
2032	variable rates	200,000	200,000		
Total first mortgage bonds		2,279,716	2,482,538		
Pollution control obligations (Note 8)		1,661,250	1,661,290		
Other long-term debt (Note 8)		135,058	117,344		
Unamortized debt premium (discount), net		(34,094)	(34,333)		
Total long-term debt (annual interest requirement -- $320,505,000)		4,041,930	4,226,839		
Less amount due within one year (Note 8)		10,543	95,823		
Long-term debt excluding amount due within one year		4,031,387	4,131,016	46.0	47.4
TOTAL CAPITALIZATION		$ 8,769,632	$ 8,718,295	100.0 %	100.0%

</TABLE>

The accompanying notes are an integral part of these statements.

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 1993, 1992, and 1991
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

<S>	1993 <C>	1992 (in thousands) <C>	1991 <C>
BALANCE AT BEGINNING OF PERIOD	$ 1,159,380	$ 1,038,012	$ 944,774
Net income after dividends on preferred stock	569,853	520,538	474,855
Cash dividends on common stock	(402,400)	(384,000)	(375,200)
Preferred stock transactions, net	(10,386)	(15,170)	(6,417)
BALANCE AT END OF PERIOD (NOTE 8)	$ 1,316,447	$ 1,159,380	$ 1,038,012

STATEMENTS OF PAID-IN CAPITAL
For the Years Ended December 31, 1993, 1992, and 1991
Georgia Power Company 1993 Annual Report

	1993	1992 (in thousands)	1991
BALANCE AT BEGINNING OF PERIOD	$ 2,384,140	$ 2,383,800	$ 2,383,800

Contributions to capital by parent company	208	340	-
BALANCE AT END OF PERIOD	$ 2,384,348	$ 2,384,140	$ 2,383,800

</TABLE>
The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 1993, 1992, and 1991
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

<S>	1993 <C>	1992 (in thousands) <C>	1991 <C>
OPERATING ACTIVITIES:			
Net income	$ 620,527	$ 578,480	$ 536,556
Adjustments to reconcile net income to net cash provided by operating activities --			
Depreciation and amortization	475,152	471,014	480,318
Deferred income taxes and investment tax credits, net	150,735	189,251	43,695
Allowance for equity funds used during construction	(3,168)	(5,855)	(9,083)
Deferred Plant Vogtle costs	36,284	(30,804)	(18,541)
Non-cash proceeds from settlement of disputed contracts (Note 3)	-	(4,982)	(103,846)
Provision for separation benefits	-	-	52,952
Gain on asset sales	(35,514)	(12)	(36,835)
Other, net	(10,713)	(9,756)	(42,141)
Changes in certain current assets and liabilities --			
Receivables, net	27,088	(31,348)	23,920
Inventories	82,433	(65,621)	24,130
Payables	17,364	25,303	(23,075)
Taxes accrued	15,377	(22,828)	76,932
Energy cost recovery, retail	(74,260)	(46,615)	(4,594)
Other	(35,691)	(16,518)	(17,561)
Net cash provided from operating activities	1,265,614	1,029,709	982,827
INVESTING ACTIVITIES:			
Gross property additions	(674,432)	(508,444)	(548,051)
Sales of property	261,687	46	291,075
Other	(43,154)	42,892	931
Net cash used for investing activities	(455,899)	(465,506)	(256,045)
FINANCING ACTIVITIES AND CAPITAL CONTRIBUTIONS:			
Proceeds:			
Preferred stock	175,000	195,000	100,000
First mortgage bonds	1,135,000	975,000	-
Pollution control bonds	145,425	161,955	80,420
Long-term notes	37,000	-	-
Retirements:			
Preferred stock	(245,005)	(165,004)	(100,000)
First mortgage bonds	(1,337,822)	(1,381,300)	(598,384)
Pollution control bonds	(145,465)	(160,205)	(83,265)
Other long-term debt	(19,451)	(567)	(1,130)
Interim obligations, net	(51,444)	334,671	199,000
Payment of preferred stock dividends	(53,123)	(60,475)	(60,766)
Payment of common stock dividends	(402,400)	(384,000)	(375,200)
Miscellaneous	(63,648)	(70,986)	(17,613)
Net cash used for financing activities	(825,933)	(555,911)	(856,938)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(16,218)	8,292	(130,156)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	22,114	13,822	143,978
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,896	$ 22,114	$ 13,822
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year for --			
Interest (net of amount capitalized)	$420,107	$435,203	$488,431
Income taxes	275,867	190,674	214,809

</TABLE>
The accompanying notes are an integral part of these statements.

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 1993 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

GENERAL

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five operating companies, Southern Company Services (SCS), Southern Electric International (Southern Electric), and Southern Nuclear Operating Company (Southern Nuclear), and various other subsidiaries related to foreign utility operations and domestic non-utility operations. The operating companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company) provide electric service in four southeastern states. Intracompany contracts dealing with jointly owned generating facilities, transmission lines and exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission. SCS provides, at cost, specialized services to The Southern Company and each of the subsidiary companies. Southern Electric designs, builds, owns, and operates power production facilities and provides a broad range of technical services to industrial companies and utilities in the United States and a number of international markets. Southern Nuclear provides support services for nuclear power plants in the Southern electric system.

The Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935. Both The Southern Company and its subsidiaries are subject to the regulatory provisions of this act. The Company is also subject to regulation by the FERC and the Georgia Public Service Commission (GPSC). The Company follows generally accepted accounting principles and complies with the accounting policies and practices prescribed by the respective regulatory commissions.

Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation.

REVENUES AND FUEL COSTS

The Company accrues revenues for services rendered but unbilled at the end of each fiscal period. Fuel costs are expensed as fuel is used. The Company is authorized by state law and FERC regulations to recover fuel costs and the fuel component of purchased energy costs through fuel cost recovery provisions, which are periodically adjusted to reflect increases or decreases in such costs. Revenues are adjusted for differences between recoverable fuel costs and amounts actually recovered in current rates. Fuel costs were under recovered by $79 million and $4 million at December 31, 1993, and 1992, respectively. These amounts are included in customer accounts receivable on the balance sheets. The fuel cost recovery rate was increased effective December 6, 1993.

The cost of nuclear fuel is amortized to fuel expense based on estimated thermal units used to generate electric energy and includes a provision for the disposal of spent fuel. Total charges for nuclear fuel amortized to expense were $75 million in 1993, $84 million in 1992, and $93 million in 1991. The Company has contracted with the U.S. Department of Energy (DOE) for permanent disposal of spent fuel beginning in 1998; however, the actual year this service will begin is uncertain. Pending permanent disposition of the spent fuel, sufficient storage capacity is available at Plant Hatch into 2003 and at Plant Vogtle into 2009. Also, the Energy Policy Act of 1992 required the establishment in 1993 of a Uranium Enrichment Decontamination and Decommissioning Fund which is to be funded, in part, by a special assessment on utilities with nuclear plants. This fund will be used by the DOE for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The law provides that utilities will recover these payments in the same manner as any other fuel expense. The Company -- based on its ownership interest -- estimates its total assessment under this law to be approximately $42 million to be paid over a 15-year period beginning in 1993. This obligation is recognized in the accompanying Balance Sheets and is being recovered through the fuel cost recovery provisions. The remaining liability at December 31, 1993, is $39 million.

NUCLEAR REFUELING OUTAGE COSTS

Prior to 1992, the Company expensed nuclear refueling outage costs as incurred during the outage period. Pursuant to the 1991 GPSC retail rate order, the Company began accounting for these costs on a normalized basis in 1992. Under this method of accounting, refueling outage costs are deferred and subsequently amortized to expense over the operating cycle of each unit, which is normally 18 months. Deferred nuclear outage costs were $17 million and $6 million at December 31, 1993 and 1992, respectively.

DEPRECIATION

Depreciation is provided on the cost of depreciable utility plant in service and is calculated primarily on the straight-line basis over the estimated composite service life of the property. The composite rate of depreciation was 3.1 percent in 1993 and 1992, and 3.2 percent in 1991. Effective October 1991, the Company adopted lower depreciation rates consistent with the 1991 GPSC retail rate order. When a property unit is retired or otherwise disposed of in the normal course of business, its costs and the costs of removal, less salvage, are charged to the accumulated provision for depreciation. Minor items of property included in the cost of the plant are retired when the related property unit is retired.

NUCLEAR DECOMMISSIONING

In 1988, the Nuclear Regulatory Commission (NRC) adopted regulations requiring all licensees operating commercial nuclear power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. Reasonable assurance may be in the form of an external sinking fund, a surety method, or prepayment. The Company has established external trust funds to comply with the NRC's regulations. Prior to the enactment of these regulations, the Company had internally reserved nuclear decommissioning costs. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor.

The estimated cost of decommissioning and the amounts being recovered through rates at December 31, 1993, for the Company's ownership interest in plants

Hatch and Vogtle were as follows:

<TABLE>
<CAPTION>

<S>	Plant Hatch <C>	Plant Vogtle <C>
Site study basis (year)	1990	1990
Estimated completion of decommissioning (year)	2027	2037
Cost of decommissioning:	(in millions)	
Radiated structures	$184	$155
Non-radiated structures	35	62
Contingency	55	54
Total costs	$274	$271
	(in millions)	
Approved for ratemaking	$184	$155
Amount expensed in 1993	$ 6	$ 6
Balance in external trust fund	$ 22	$ 16
Balance in internal reserve	$ 33	$ 11

</TABLE>

The amounts in the internal reserve are being transferred into the external trust fund over a period of approximately nine years as approved by the GPSC in its 1991 retail rate order.

The estimates approved by the GPSC for ratemaking exclude costs of non-radiated structures and site contingency costs. The actual decommissioning cost may vary from the above estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The Company expects the GPSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

PLANT VOGTLE PHASE-IN PLANS

In 1987 and 1989, the GPSC ordered that the costs of Plant Vogtle Units 1 and 2 be phased into rates under plans that meet the requirements of Financial Accounting Standards Board (FASB) Statement No. 92, Accounting for Phase-In Plans. In 1991, the GPSC modified the phase-in plans. In addition, the Company deferred certain Plant Vogtle operating expenses and financing costs under accounting orders issued by the GPSC. See Note 3 for further information.

INCOME TAXES

The Company provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average lives of the related property.

In years prior to 1993, income taxes were accounted for and reported under Accounting Principles Board Opinion No. 11. Effective January 1, 1993, the Company adopted FASB Statement No. 109, Accounting for Income Taxes. See Note 7 to the financial statements for further information.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) AND DEFERRED RETURN

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. For the years 1993, 1992 and 1991, the average AFUDC rates were 4.87 percent, 7.16 percent and 9.90 percent, respectively. The reduction in the average AFUDC rate since 1991 reflects the Company's greater use of lower cost short-term debt.

The Company also imputed a return on its investment in Plant Vogtle Units 1 and 2 after they began commercial operation, under short-term cost deferrals and phase-in plans as described in Note 3. AFUDC and the Vogtle deferred returns, net of taxes, as a percentage of net income after dividends on preferred stock, amounted to 1.4 percent, 2.1 percent and 9.2 percent for 1993, 1992 and 1991, respectively.

UTILITY PLANT

Utility plant is stated at original cost with the exception of Plant Vogtle, which is stated at cost less regulatory disallowances. Original cost includes materials; labor; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the estimated cost of funds used during construction.

CASH AND CASH EQUIVALENTS

For purposes of the Statements of Cash Flows, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

FINANCIAL INSTRUMENTS

All financial instruments of the Company -- for which the carrying amount does not approximate fair value -- are shown in the table below at December 31:

<TABLE>
<CAPTION>

	1993 Carrying Amount	1993 Fair Value
	(in millions)	
<S>	<C>	<C>
Nuclear decommissioning trusts	$ 38	$ 40
Long-term debt	3,954	4,197

	1992 Carrying	Fair

	Amount	Value
	(in millions)	
Nuclear decommissioning trusts	$ 20	$ 21
Investment securities	108	121
Long-term debt	4,130	4,404
Preferred stock subject to mandatory redemption	70	76

</TABLE>

The fair values of nuclear decommissioning trusts and investment securities were based on listed closing market prices. The fair values for long-term debt and preferred stock subject to mandatory redemption were based on either closing market prices or closing prices of comparable instruments.

MATERIALS AND SUPPLIES

Generally, materials and supplies include the cost of transmission, distribution and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. In December 1992, the Company converted to the inventory method of accounting for certain emergency spare parts. This conversion resulted in a regulatory liability that is being amortized as credits to income over

approximately four years. This conversion will not have a material effect on income in any year.

VACATION PAY

Company employees earn vacation in one year and take it in the subsequent year. However, for ratemaking purposes, vacation pay is recognized as an allowable expense only when paid. Consistent with this ratemaking treatment, the Company accrues a current liability for earned vacation pay and records a current asset representing the future recoverability of this cost. This amount was $42 million at December 31, 1993, and $40 million at December 31, 1992. In 1994, approximately 72 percent of the 1993 deferred vacation costs will be expensed, and the balance will be charged to construction and other accounts.

2. RETIREMENT BENEFITS

PENSION PLAN

The Company has a defined benefit, trusteed, non-contributory pension plan covering substantially all regular employees. Benefits are based on the greater of amounts resulting from two different formulas: years of service and final average pay or years of service and a flat dollar benefit. The Company uses the "entry age normal method with a frozen initial liability" actuarial method for funding purposes, subject to limitations under federal income tax regulations. Amounts funded to the pension fund are primarily invested in equity and fixed-income securities. FASB Statement No. 87, Employers' Accounting for Pensions, requires use of the projected unit credit actuarial method for financial reporting purposes.

POSTRETIREMENT BENEFITS

The Company also provides certain medical care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits when they retire. For medical care benefits, a qualified trust has been established for funding amounts to the extent deductible under federal income tax regulations. Amounts funded are primarily invested in debt and equity securities. Accrued costs of life insurance benefits, other than current cash payments for retirees, currently are not being funded.

Effective January 1, 1993, the Company adopted FASB Statement No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, on a prospective basis. Statement No. 106 requires that medical care and life insurance benefits for retired employees be accounted for on an accrual basis using a specified actuarial method, "benefit/years-of-service."

In October 1993, the GPSC ordered the Company to phase in the adoption of Statement No. 106 to cost of service over a five-year period, whereby one-fifth of the additional expense was recognized -- approximately $6 million -- in 1993 and the remaining additional expense was deferred. An additional one-fifth of the costs will be expensed each succeeding year until the costs are fully reflected in cost of service in 1997. The cost deferred during the five-year period will be amortized to expense over a 15-year period beginning in 1998. As a result of the regulatory treatment allowed by the GPSC, the adoption of Statement No. 106 did not have a material impact on net income.

Prior to 1993, the Company recognized these cost on a cash basis as payments were made. The total costs of such benefits recognized by the Company in 1993, 1992, and 1991 were $56 million, $13 million, and $9 million, respectively.

STATUS AND COST OF BENEFITS

Shown in the following tables are actuarial results and assumptions for pension and postretirement medical and life insurance benefits as computed under the requirements of Statement Nos. 87 and 106, respectively. Retiree medical and life insurance information is shown only for 1993 because Statement No. 106 was adopted as

of January 1, 1993, on a prospective basis. The funded status of the plans at December 31 was as follows:

<TABLE>
<CAPTION>

	Pension 1993	Pension 1992
	(in millions)	
<S>	<C>	<C>
Actuarial present value of benefit obligations:		
Vested benefits	$ 655	$ 557
Non-vested benefits	35	26
Accumulated benefit obligation	690	583
Additional amounts related to projected salary increases	257	293
Projected benefit obligation	947	876
Less:		
Fair value of plan assets	1,495	1,341
Unrecognized net gain	(490)	(413)
Unrecognized prior service cost	31	33
Unrecognized transition asset	(62)	(67)
Prepaid asset recognized in the Balance Sheets	$ 27	$ 18

</TABLE>

<TABLE>
<CAPTION>

	Postretirement Medical	Postretirement Life
	1993	
	(in millions)	
<S>	<C>	<C>
Actuarial present value of benefit obligation:		
Retirees and dependents	$136	$32
Employees eligible to retire	12	-
Other employees	206	40
Accumulated benefit obligation	354	72
Less:		
Fair value of plan assets	30	1
Unrecognized net loss (gain)	40	(6)
Unrecognized transition obligation	251	69
Accrued liability recognized in the Balance Sheets	$ 33	$ 8

</TABLE>

Weighted average rates used in actuarial calculations:

	1993	1992	1991
Discount	7.5%	8.0%	8.0%
Annual salary increase	5.0	6.0	6.0
Long-term return on plan assets	8.5	8.5	8.5

An additional assumption used in measuring the accumulated postretirement medical benefit obligation was a weighted average medical care cost trend rate of 11.3 percent for 1993, decreasing gradually to 6.0 percent through the year 2000 and remaining at that level thereafter. An annual increase in the assumed medical care cost trend rate by 1.0 percent would increase the accumulated medical benefit obligation as of December 31, 1993, by $68 million and the aggregate of the service and interest cost components of the net retiree medical cost by $7 million.

The components of the plans' net costs are shown below:

	Pension		
	1993	1992	1991
	(in millions)		
Benefits earned during the year	$ 33	$ 34	$ 32
Interest cost on projected benefit obligation	69	65	61
Actual return on plan assets	(194)	(61)	(334)
Net amortization and deferral	84	(38)	247
Net pension cost (income)	$ (8)	$ -	$ 6

Of net pension costs (income) recorded, $(6) million in 1993 and $5 million in 1991, were recorded to operating expense, with the balance being recorded to construction and other accounts.

	Postretirement	
	Medical	Life
	1993	
	(in millions)	
Benefits earned during the year	$11	$ 3
Interest cost on accumulated benefit obligation	23	6
Amortization of transition obligation over 20 years	12	3
Actual return on plan assets	(4)	-
Net amortization and deferral	2	-
Net postretirement cost	$44	$12

Of the above net postretirement medical and life insurance costs recorded in 1993, $21 million was charged to operating expenses, $21 million was deferred, and the remainder was charged to construction and other accounts.

3. LITIGATION AND REGULATORY MATTERS

DEMAND-SIDE CONSERVATION PROGRAMS

In October 1993, a Superior Court of Fulton County, Georgia, judge ruled that rate riders previously approved by the GPSC for recovery of the Company's costs incurred in connection with demand-side conservation programs were unlawful. The judge held that the GPSC lacked statutory authority to approve such rate riders except through general rate case proceedings and that those procedures had not been followed. The Company has suspended collection of the demand-side conservation costs and appealed the court's decision to the Georgia Court of Appeals. In December 1993, the GPSC approved the Company's request for an accounting order allowing the Company to defer all current unrecovered and future costs related to these programs until the court's decision is reversed or until the next general rate case proceeding. An association of industrial customers has filed a petition for review of such accounting order in the Superior Court of Fulton County, Georgia. The Company's costs related to these conservation programs through 1993 were $60 million of which $15 million has been collected and the remainder deferred. The estimated costs, assuming no change in the programs certified by the GPSC, are $38 million in 1994 and $40 million in 1995.

The final outcome of this matter cannot now be determined; however, in management's opinion, the final outcome will not have a material adverse effect on these financial statements.

RETAIL RATEPAYERS' SUIT CONCLUDED

In March 1993, several retail ratepayers of Georgia Power filed a civil complaint in the Superior Court of Fulton County, Georgia, against Georgia Power, The Southern Company, the system service company, and Arthur Andersen & Co. The complaint alleged that Georgia Power obtained excessive rate increases by improper accounting for spare parts and sought actual damages estimated by the plaintiffs to be in excess of $60 million -- plus treble and punitive damages -- for alleged violations of the Georgia Racketeer Influenced and Corrupt Organizations Act and other state statutes, statutory and common law fraud, and negligence. These state law allegations were substantially the same as those included in a 1989 suit brought in federal district court in Georgia. That suit and similar ones filed in Alabama, Florida, and Mississippi federal courts were subsequently dismissed.

The defendants' motions to dismiss the current complaint were granted by the Superior Court of Fulton County, Georgia, in July 1993. In January 1994, the plaintiffs' appeal of the dismissal to the Supreme Court of Georgia was rejected. This matter is now concluded.

GULF STATES SETTLEMENT

On November 7, 1991, subsidiaries of The Southern Company entered into a settlement agreement with Gulf States that resolved litigation between the companies that had been pending since 1986 and arose out of a dispute over certain unit power and long-term power sales contracts. In 1993, all remaining terms and obligations of the settlement agreement were satisfied.

Based on the value of the settlement proceeds received, the Company recorded increases of $3 million in 1992 and $89 million in 1991 net income.

FERC REVIEW OF EQUITY RETURNS

In May 1991, the FERC ordered that hearings be conducted concerning the reasonableness of the Southern electric system's wholesale rate schedules and contracts that have a return on common equity of 13.75 percent or greater. The contracts that could be affected by the hearings include substantially all of the transmission, unit power, long-term power, and other similar contracts. Any changes in the rate of return on common equity that may occur as a result of this proceeding would be effective 60 days after a proper notice of the proceeding is published. A notice was published on May 10, 1991.

In August 1992, a FERC administrative law judge issued an opinion that changes in rate schedules and contracts were not necessary and that the FERC staff failed to show how any changes were in the public interest. The FERC staff has filed exceptions to the administrative law judge's opinion, and the matter remains pending before the FERC.

The final outcome of this matter cannot now be determined; however, in management's opinion, the final outcome will not have a material adverse effect on the Company's financial statements.

PLANT VOGTLE PHASE-IN PLANS

Pursuant to orders from the GPSC, the Company recorded a deferred return under phase-in plans for Plant Vogtle Units 1 and 2 until October 1991 when the allowed investment was fully reflected in rates. In addition, the GPSC issued two separate accounting orders that required the Company to defer substantially all operating and financing costs related to both units until rate orders addressed these costs. These GPSC orders provide for the recovery of deferred costs within 10 years. The GPSC modified the phase-in plans in 1991 to accelerate the recognition of costs previously deferred under the Plant Vogtle Unit 2 phase-in plan and to levelize the remaining Plant Vogtle declining capacity buyback expenses.

Under these orders, the Company has deferred and begun amortizing these costs (as recovered through rates) as follows:

	1993	1992	1991
	(in millions)		
Deferred expenses:			
Capacity buybacks	$(38)	$(100)	$(30)
Other operating	-	-	(7)
Amortization of previously deferred return and expenses	74	69	53
Deferred expenses, net	36	(31)	16
Deferred return	-	-	35
Less income taxes	-	23	8
Net (deferral) amortization	36	(8)	(11)
Effect of adoption of FASB Statement No. 109	160	-	-
Deferred costs at beginning of year	383	375	364
Deferred costs at end of year	$507	$ 383	$375

NUCLEAR PERFORMANCE STANDARDS

In October 1989, the GPSC adopted a nuclear performance standard for the Company's nuclear generating units under which the performance of plants Hatch and Vogtle will be evaluated every three years. The performance standard is based on each unit's capacity factor as compared to the average of all U.S. nuclear units operating at a capacity factor of 50% or higher during the three-year period of evaluation. Depending on the performance of the units, the Company could receive a monetary reward or penalty under the performance standards criteria. The first evaluation was conducted in 1993 for performance during the 1990-92 period. During this three-year period, the Company's units performed at an average capacity factor of 81 percent compared to an industry average of approximately 73 percent. Based on these results, the GPSC approved a performance reward of approximately $8.5 million for the Company. This reward is being collected through the retail fuel cost recovery provision and recognized in income over a 36- month period beginning November, 1993.

4. COMMITMENTS AND CONTINGENCIES

CONSTRUCTION PROGRAM

The Company is engaged in a continuous construction program and currently estimates property additions to be approximately $688 million in 1994, $555 million in 1995 and $629 million in 1996. These estimated additions include AFUDC of $19 million in 1994, $27 million in 1995, and $18 million in 1996. The estimates for property additions for the three-year period include $88 million committed to meeting the requirements of the Clean Air Act.

While the Company has no new baseload generating plants under construction, the construction of nine combustion turbine peaking units is planned to be completed by 1996. In addition, significant construction of transmission and distribution facilities, and upgrading and extending the useful life of generating plants will continue. The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors, including, but not limited to, changes in business conditions, load growth estimates, environmental regulations, and regulatory requirements.

FUEL COMMITMENTS

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels and other financial commitments. Total estimated long-term obligations were approximately $4.8 billion at December 31, 1993. Additional commitments for coal and for nuclear fuel will be required in the future to supply the Company's fuel needs.

OPERATING LEASES

The Company has entered into coal rail car rental agreements with various terms and expiration dates. Rental expense totaled $8 million, $7 million, and $5 million for 1993, 1992, and 1991, respectively. Minimum annual rental commitments for noncancellable rail car leases are $9 million annually for years 1994 through 1998, and total approximately $191 million thereafter.

ROCKY MOUNTAIN PROJECT STATUS

In its 1985 financing order, the GPSC concluded that completion of the Rocky Mountain pumped storage hydroelectric project in 1991 as then planned was not economically justifiable and reasonable and withheld authorization for the Company to spend funds from approved securities issuances on that project. In 1988, the Company and Oglethorpe Power Corporation (OPC) entered into a joint ownership agreement for OPC to assume responsibility for the construction and operation of the project, as discussed in Note 5. The joint ownership agreement significantly reduces the risk of the project being canceled. However, full recovery of the Company's costs depends on the GPSC's treatment of the project's cost and disposition of the project's capacity output. In the event the Company cannot demonstrate to the GPSC the project's economic viability based on current ownership, construction schedule, and costs, then part or all of such costs may have to be written off in accordance with FASB Statement No. 90, Accounting for Abandonments and Disallowed Plant Costs. At December 31, 1993, the Company's investment in the project amounted to approximately $197 million. AFUDC accrued on the Rocky Mountain project has not been credited to income or included in the project cost since December 1985. If accrual of AFUDC is not resumed, the Company's portion of the estimated total plant additions at completion would be approximately $199 million. The plant is currently scheduled to begin commercial operation in 1995.

The Company has held preliminary discussions with other parties regarding the potential disposition of its remaining interest in the project.

The ultimate outcome of this matter cannot now be determined.

NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The act limits to $9.4 billion public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $200 million by private insurance, with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. A company could be assessed up to $79 million per incident for each licensed reactor it operates but not more than an aggregate of $10 million per incident to be paid in a calendar year for each reactor. Such maximum assessment for the Company -- based on its ownership and buyback interests -- is $171 million per incident but not more than an aggregate of $22 million to be paid for each incident in any one year.

The Company is a member of Nuclear Mutual Limited (NML), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities. The members are subject to a retrospective premium adjustment in the event that losses exceed accumulated reserve funds. The Company's maximum assessment per incident is limited to $18 million under current policies.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million NML coverage. This excess insurance is provided by Nuclear Electric

Insurance Limited (NEIL), a mutual insurance company, and American Nuclear Insurers/Mutual Atomic Energy Liability Underwriters.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can be insured against increased costs of replacement power in an amount up to $3.5 million per week -- starting 21 weeks after the outage -- for one year and up to $2.3 million per week for the second and third years.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The maximum assessments per incident under the current policies for the Company would be $15 million for excess property damage and $13 million for replacement power.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies issued or renewed on or after April 2, 1991, shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

The Company participates in an insurance program for nuclear workers that provides coverage for worker tort claims filed for bodily injury caused at commercial nuclear power plants. In the event that claims for this insurance exceed the accumulated reserve funds, the Company could be subject to a maximum total assessment of $7 million.

5. FACILITY SALES AND JOINT OWNERSHIP AGREEMENTS

Since 1975, the Company has sold undivided interests in plants Hatch, Wansley, Vogtle, and Scherer Units 1 and 2, together with transmission facilities, to OPC, an electric membership generation and transmission corporation; the Municipal Electric Authority of Georgia (MEAG), a public corporation and an instrumentality of the state of Georgia; and the City of Dalton, Georgia. The Company has sold an interest in Plant Scherer Unit 3 to Gulf Power, an affiliate.

Additionally, the Company has completed two of four separate transactions to sell Unit 4 of Plant Scherer to Florida Power & Light Company (FPL) and Jacksonville Electric Authority (JEA) for a total price of approximately $806 million, including any gains on these transactions. FPL will eventually own approximately 76.4 percent of the unit, with JEA owning the remainder. Georgia Power will continue to operate the unit.

The completed and scheduled remaining transactions are as follows:

<TABLE>
<CAPTION>

Closing Date	Capacity (in megawatts)	Percent Ownership	Amount (in millions)	After-Tax Gain
<S>	<C>	<C>	<C>	<C>
July 1991	290	35.46%	$291	$14
June 1993	258	31.44	253	18
June 1994	135	16.55	132	10
June 1995	135	16.55	130	10
Total	818	100.00%	$806	$52

</TABLE>

Except as otherwise noted, the Company has contracted to operate and maintain all jointly owned facilities. The Company includes its proportionate share of plant operating expenses in the corresponding operating expenses in the Statements of Income.

As discussed in Note 4, the Company and OPC have a joint ownership arrangement for the Rocky Mountain pumped storage hydroelectric project under which the Company will retain its present investment in the project and OPC will finance and complete the remainder of the project and operate the completed facility. Based on current cost estimates the Company's ownership will be approximately 25% of the project (194 megawatts of capacity) at completion.

The Company will own six of eight 80 megawatt combustion turbine generating units and 75% of the related common facilities being jointly constructed with Savannah Electric, an affiliate. The Company's investment in the project at December 31, 1993, was $100 million and is expected to total approximately $182 million when the project is completed. All units are

expected to be completed by June, 1995. Savannah Electric will operate these units.

In connection with the joint ownership arrangements for plants Vogtle and Scherer, the Company has made commitments to purchase declining fractions of OPC's and MEAG's capacity and energy from these units. These commitments are in effect during periods of up to 10 years following commercial operation (and with regard to a portion of a 5 percent interest in Plant Vogtle owned by MEAG, until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest). The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Except as noted below, the cost of such capacity and energy is included in purchased power from non-affiliates in the Company's Statements of Income. Capacity payments totaled $183 million, $289 million and $320 million in 1993, 1992 and 1991, respectively. The Plant Scherer buyback agreements ended in 1993. The current projected Plant Vogtle capacity payments for the next five years are as follows: $132 million in 1994, $77 million in 1995, $70 million in 1996, $59 million in 1997 and $59 million in 1998. Portions of the payments noted above relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions was written off in 1987 and 1990. Additionally, the Plant Vogtle declining capacity buyback expense is being levelized over a six-year period. See Note 3 for further information.

At December 31, 1993, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation, were as follows:
<TABLE>
<CAPTION>

Facility (Type)	Total Capacity (megawatts)	Company Ownership
<S>	<C>	<C>
Plant Vogtle (nuclear)	2,320	45.7%
Plant Hatch (nuclear)	1,630	50.1
Plant Wansley (coal)	1,779	53.5
Plant Scherer (coal)		
Units 1 and 2	1,636	8.4
Unit 3	818	75.0
Unit 4	818	33.1

Facility (Type)	Investment (in millions)	Accumulated Depreciation
Plant Vogtle (nuclear)	$3,285 (1)	$540
Plant Hatch (nuclear)	840	325
Plant Wansley (coal)	286	125
Plant Scherer (coal)		
Units 1 and 2	111	33
Unit 3	539	107
Unit 4	236	31

</TABLE>

(1) Investment net of write-offs.

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of Southern Electric Generating Company (SEGCO), which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power under a contract expiring in 1994, which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service and return on investment, whether or not SEGCO has any capacity and energy available. An amended contract has been filed with the FERC with substantially the same provisions, but the term thereof would be extended automatically for two year periods, subject to any party's right to cancel upon two year's notice. The Company's share of expenses included in purchased power from affiliates in the Statements of

Income, is as follows:

	1993	1992	1991
	(in millions)		
Energy	$ 81	$ 66	$ 74
Capacity	9	9	10
Total	$ 90	$ 75	$ 84
Kilowatt-hours	3,352	2,664	2,911

At December 31, 1993, the capitalization of SEGCO consisted of $58 million of equity and $84 million of long-term debt on which the annual interest requirement is $3.8 million.

6. LONG-TERM POWER SALES AGREEMENTS

The Company and the operating affiliates of The Southern Company have entered into long-term contractual agreements for the sale of capacity and energy to certain non-affiliated utilities located outside the system's service territory. Certain of these agreements are non-firm and are based on the capacity of the Southern system. Other agreements are firm and pertain to capacity related to specific generating units. Because energy is generally sold at cost under these agreements, it is primarily the capacity revenues that affect the Company's profitability. The capacity revenues have been as follows:

Year	Unit Power Sales	Other Long-Term
	(in millions)	
1993	$135	$17
1992	223	10
1991	263	11

Long-term non-firm power of 400 megawatts was sold by the Southern electric system in 1993 to Florida Power Corporation (FPC). This amount decreases to 200 megawatts in 1994 and the contract expires at year-end. Sales under these long-term non-firm power sales agreements are made from available power pool energy, and the revenues from the sales are shared by the operating affiliates.

Unit power from specific generating plants is being sold to FPL, JEA, and the City of Tallahassee, Florida and beginning in 1994 to FPC. Under these agreements, the Company sold approximately 830 megawatts of capacity in 1993 and is scheduled to sell approximately 403 megawatts of capacity in 1994. Thereafter, these sales will decline to an estimated 157 megawatts by the end of 1996 and will remain at that approximate level through 1999. After 2000, capacity sales will decline to approximately 101 megawatts -- unless reduced by FPL and JEA -- until the expiration of the contracts in 2010.

7. INCOME TAXES

Effective January 1, 1993, the Company adopted FASB Statement No. 109, Accounting for Income Taxes. The adoption of Statement No. 109 resulted in cumulative adjustments that had no material effect on net income. The adoption also resulted in the recording of additional deferred income taxes and related assets and liabilities. The related assets of $993 million are revenues to be received from customers. These assets are attributable to tax benefits flowed-through to customers in prior years, and taxes applicable to capitalized AFUDC. The related liabilities of $453 million are revenues to be refunded to customers. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. Additionally, deferred income taxes related to accelerated tax depreciation previously shown as a reduction to utility plant were reclassified.

Details of the federal and state income tax provisions are as follows:

<TABLE>

<CAPTION>

Total provision for income taxes:	1993	1992 (in millions)	1991
<S>	<C>	<C>	<C>
Federal:			
Currently payable	$223	$139	$267
Deferred -			
Current year	181	170	97
Reversal of prior years	(40)	(6)	(52)
Deferred investment tax credits	(18)	(6)	(10)
	346	297	302
State:			
Currently payable	41	24	47
Deferred -			
Current year	31	35	17
Reversal of prior years	(3)	(3)	(9)
	69	56	55
Total	415	353	357
Less:			
Income taxes charged (credited) to other income	(37)	(25)	8
Federal and state income taxes charged to operations	$452	$378	$349

</TABLE>

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax basis, which give rise to deferred tax assets and liabilities are as follows:

<TABLE>
<CAPTION>

	1993 (in millions)
<S>	<C>
Deferred tax liabilities:	
Accelerated depreciation	$1,458
Property basis differences	1,163
Deferred Plant Vogtle costs	161
Premium on reacquired debt	63
Fuel clause underrecovered	32
Other	62
Total	2,939
Deferred tax assets:	
Other basis differences	263
Federal effect of state deferred taxes	92
Other deferred costs	61
Disallowed plant buybacks	29
Accrued interest	24
Other	12
Total	481
Net deferred tax liabilities (assets)	2,458
Portion included in current assets	(22)
Accumulated deferred income taxes in the Balance Sheets	$2,480

</TABLE>

Deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the Statements of Income. Credits amortized in this manner amounted to $19 million in 1993, $19 million in 1992, and $27 million in 1991. At December 31, 1993, all investment tax credits available to reduce federal income taxes payable had been utilized.

A reconciliation of the federal statutory tax rate to effective income tax rate is as follows:

	1993	1992	1991
Federal statutory rate	35%	34%	34%
State income tax, net of federal deduction	4	4	4
Non-deductible book depreciation	3	3	4
Difference in prior years' deferred and current tax rate	(1)	(1)	(1)
Other	(1)	(2)	(1)
Effective income tax rate	40%	38%	40%

The Southern Company and its subsidiaries file a consolidated federal income tax return. Under a joint consolidated income tax agreement, each company's current and deferred tax expense is computed on a stand-alone basis, and consolidated tax savings are allocated to each company based on its ratio of taxable income to total consolidated taxable income.

8. CAPITALIZATION

COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture contains various common stock dividend restrictions that remain in effect as long as the bonds are outstanding. At December 31, 1993, $742 million of retained earnings were restricted against the payment of cash dividends on common stock under terms of the mortgage indenture. Supplemental indentures in connection with future first mortgage bond issues may contain more stringent common stock dividend restrictions than those currently in effect.

The Company's charter limits cash dividends on common stock to the lesser of the retained earnings balance or 75 percent of net income available for such stock during a prior period of 12 months if the ratio of common stock equity to total capitalization, including retained earnings, adjusted to reflect the payment of the proposed dividend, is below 25 percent, and to 50 percent of such net income if such ratio is less than 20 percent. At December 31, 1993, the ratio as defined was 46.1 percent.

REMARKETED BONDS

In 1992, the Company issued two series of variable rate first mortgage bonds each with principal amounts of $100 million due 2032. The current composite interest rate on the bonds is 6.20 percent and is fixed for the first three years of the issues.

POLLUTION CONTROL BONDS

The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control and industrial development revenue bonds. The Company has authenticated and delivered to trustees an aggregate of $407.7 million of its first mortgage bonds, which are pledged as security for its obligations under pollution control and industrial development contracts. No interest on these first mortgage bonds is payable unless and until a default occurs on the installment purchase or loan agreements. An aggregate of approximately $1.3 billion of the pollution control and industrial development bonds is secured by a subordinated interest in specific property of the Company.

Details of pollution control bonds are as follows:

Maturity	Interest Rates	1993	1992

		(in millions)	
2003-2007	5.70% to 6.75%	$ 90	$ 103
2008-2011	6.375% & Variable	19	32
2014-2018	6.00% to 12.25%	1,237	1,283
2019-2023	5.75% to 7.25% & Variable	315	243
Total pollution control bonds		$ 1,661	$ 1,661

</TABLE>

BANK CREDIT ARRANGEMENTS

At the beginning of 1994, the Company had unused credit arrangements with banks totaling $540 million, of which $10 million expires June 30, 1994, $130 million expires at May 1, 1996, and $400 million expires at June 30, 1996.

The $400 million expiring June 30, 1996, is under revolving credit arrangements with several banks providing the Company, Alabama Power, and The Southern Company up to a total credit amount of $400 million. To provide liquidity support for commercial paper programs and for other short-term cash needs, $165 million and $135 million of the $400 million available credit are currently dedicated for the Company and Alabama Power, respectively. However, the allocations can be changed among the borrowers by notifying the respective banks.

During the term of the agreements expiring in 1996, short-term borrowings may be converted into term loans, payable in 12 equal quarterly installments, with the first installment due at the end of the first calendar quarter after the applicable termination date or at an earlier date at the companies' option. In addition, these agreements require payment of commitment fees based on the unused portions of the commitments or the maintenance of compensating balances with the banks.

The $10 million credit arrangement expiring in 1994 allows borrowings for up to 90 days. Commitment fees are based on the unused portion of the commitment.

In addition, the Company borrows under uncommitted lines of credit with banks and through a $150 million commercial paper program that has the liquidity support of committed bank credit arrangements. Average compensating balances held under these committed facilities were not material in 1993.

OTHER LONG-TERM DEBT

Assets acquired under capital leases are recorded in the Balance Sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 1993, the Company had a capitalized lease obligation for its corporate headquarters building of $88 million with an interest rate of 8.1 percent. Other capitalized lease obligations were $137 thousand with a composite interest rate of 6.8 percent.

The maturities of capital lease obligations through 1998 are approximately as follows: $423 thousand in 1994, $309 thousand in 1995, $335 thousand in 1996, $362 thousand in 1997, and $392 thousand in 1998.

The lease agreement for the corporate headquarters building provides for payments that are minimal in early years and escalate through the first 21 years of the lease. For ratemaking purposes, the GPSC has treated the lease as an operating lease and has allowed only the lease

payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes is being deferred as a cost to be recovered in the future as ordered by the GPSC. At December 31, 1993, and 1992, the interest and lease amortization deferred on the Balance Sheets are $47 million and $48 million, respectively.

In December 1993, the Company borrowed $37 million through a long-term note due in 1995.

ASSETS SUBJECT TO LIEN

The Company's mortgage dated as of March 1, 1941, as amended and supplemented, securing the first mortgage bonds issued by the Company, constitutes a direct lien on substantially all of the Company's fixed property and franchises.

LONG-TERM DEBT DUE WITHIN ONE YEAR

The current portion of the Company's long-term debt is as follows:

	1993	1992
	(in millions)	
First mortgage bonds:		
Redemption of 10.75% issue due 2018	$ -	$3.7
Redemption of variable rate issue due 2020	-	50.0
Improvement fund requirement	-	30.4
Pollution control bonds		
5.95% series sinking fund requirement	-	0.3
6.4% series sinking fund requirement	*	0.2
6.75% series sinking fund requirement	*	-
6.375% series sinking fund requirement	*	-
Other long-term debt	10.5	11.2
Total	$10.5	$95.8

*Less than .1 million

The indenture's first mortgage bond improvement fund requirement amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control obligations. The requirement may be satisfied by depositing cash or reacquired bonds, or by pledging additional property equal to 1 2/3 times the requirement. The 1993 and 1992 requirements were met in the first quarter of each year by depositing cash subsequently used to redeem bonds. The 1994 requirement was funded in December 1993.

REDEMPTION OF HIGH-COST SECURITIES

The Company plans to continue a program of redeeming or replacing high-cost debt and preferred stock in cases where opportunities exist to reduce financing costs. High-cost issues may be repurchased in the open market or called at premiums as specified under terms of the issue. They may also be redeemed at face value to meet improvement fund and sinking fund requirements, to meet replacement provisions of the mortgage, or by use of proceeds from the sale of property pledged under the mortgage. In general, for the first five years a series is outstanding the Company is prohibited from redeeming for improvement fund purposes more than 1 percent annually of the original issue amount.

9. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized quarterly financial information for 1993 and 1992 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
MARCH 1993	$1,004	$221	$108
JUNE 1993	1,096	219	141
SEPTEMBER 1993	1,376	356	245
DECEMBER 1993	975	176	76
March 1992	$ 957	$211	$ 91
June 1992	1,068	235	116
September 1992	1,280	342	227
December 1992	992	197	87

The Company's business is influenced by seasonal weather conditions and the timing of rate increases.

SELECTED FINANCIAL AND OPERATING DATA
Georgia Power Company 1993 Annual Report

<TABLE>
<CAPTION>

	1993	1992	1991
<S>	<C>	<C>	<C>
OPERATING REVENUES (IN THOUSANDS)	$ 4,451,181	$ 4,297,436	$ 4,301,428
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK (IN THOUSANDS)	$ 569,853	$ 520,538	$ 474,855
CASH DIVIDENDS ON COMMON STOCK (IN THOUSANDS)	$ 402,400	$ 384,000	$ 375,200
RETURN ON AVERAGE COMMON EQUITY (PERCENT)	14.37	13.60	12.76
TOTAL ASSETS (IN THOUSANDS)	$13,736,110	$10,964,442	$10,842,538
GROSS PROPERTY ADDITIONS (IN THOUSANDS)	$ 674,432	$ 508,444	$ 548,051
CAPITALIZATION (IN THOUSANDS):			
Common stock equity	$ 4,045,458	$ 3,888,237	$ 3,766,551
Preferred stock	692,787	692,792	607,796
Preferred stock subject to mandatory redemption	-	6,250	118,750
Long-term debt	4,031,387	4,131,016	4,553,189
Total (excluding amounts due within one year)	$ 8,769,632	$ 8,718,295	$ 9,046,286
CAPITALIZATION RATIOS (PERCENT):			
Common stock equity	46.1	44.6	41.7
Preferred stock	7.9	8.0	8.0
Long-term debt	46.0	47.4	50.3
Total (excluding amounts due within one year)	100.0	100.0	100.0
FIRST MORTGAGE BONDS (IN THOUSANDS):			
Issued	1,135,000	975,000	-
Retired	1,337,822	1,381,300	598,384
PREFERRED STOCK (IN THOUSANDS):			
Issued	175,000	195,000	100,000
Retired	245,005	165,004	100,000
SECURITY RATINGS:			
First Mortgage Bonds -			
Moody's	A3	A3	Baa1
Standard and Poor's	A-	A-	BBB+
Duff & Phelps	A+	A-	BBB+
Preferred Stock -			
Moody's	baa1	baa1	baa1
Standard and Poor's	BBB+	BBB+	BBB
Duff & Phelps	A-	BBB	BBB-
CUSTOMERS (YEAR-END):			
Residential	1,441,972	1,421,175	1,397,682
Commercial	188,820	183,784	179,933
Industrial	11,217	11,479	11,946
Other	2,322	2,269	2,190
Total	1,644,331	1,618,707	1,591,751
EMPLOYEES (YEAR-END)	12,528	12,600	13,700

</TABLE>

SELECTED FINANCIAL AND OPERATING DATA
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<TABLE>
<CAPTION>

1990	1989	1988	1987	1986	1985	1984	1983
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
$ 4,445,809	$ 4,145,240	$ 3,897,479	$ 3,786,485	$ 3,561,603	$ 3,609,140	$ 3,319,699	$ 2,869,883
$ 208,066	$ 449,099	$ 479,532	$ 240,057	$ 535,003	$ 493,717	$ 421,719	$ 304,555
$ 389,600	$ 394,500	$ 386,600	$ 377,800	$ 325,500	$ 277,500	$ 225,500	$ 189,600
5.52	11.72	13.06	6.85	16.51	17.95	18.43	15.86
$11,176,619	$11,372,346	$11,130,539	$11,197,494	$10,465,063	$ 9,030,618	$ 7,880,072	$ 6,746,247
$ 558,727	$ 727,631	$ 929,019	$ 1,034,059	$ 1,598,309	$ 1,384,182	$ 1,396,846	$ 1,015,274
$ 3,673,913	$ 3,860,657	$ 3,806,070	$ 3,538,182	$ 3,469,201	$ 3,013,707	$ 2,486,172	$ 2,089,171
607,796	607,844	657,844	657,844	732,844	632,844	482,844	432,844
125,000	155,000	162,500	166,250	112,500	120,000	127,500	131,250

5,000,225	5,054,001	4,861,378	4,825,760	4,464,857	3,878,066	3,432,606	3,128,500
$ 9,406,934	$ 9,677,502	$ 9,487,792	$ 9,188,036	$ 8,779,402	$ 7,644,617	$ 6,529,122	$ 5,781,765
39.1	39.9	40.1	38.5	39.5	39.4	38.1	36.1
7.8	7.9	8.6	9.0	9.6	9.9	9.3	9.8
53.1	52.2	51.3	52.5	50.9	50.7	52.6	54.1
100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
300,000	250,000	150,000	500,000	500,000	-	150,000	125,000
91,117	91,516	206,677	217,949	377,538	17,738	26,084	18,273
-	-	-	125,000	100,000	150,000	50,000	-
83,750	7,500	3,750	150,000	7,500	3,750	2,380	4,378
Baa1	Baa2	Baa2	Baa2	Baa1	Baa1	Baa1	Baa1
BBB+	BBB+	BBB	BBB	BBB+	BBB+	BBB+	BBB+
BBB	BBB	9	9	9	9	8	8
baa1	baa2	baa2	baa2	baa1	baa1	baa1	baa1
BBB	BBB	BBB-	BBB-	BBB	BBB	BBB	BBB
BBB-	BBB-	10	10	10	10	9	9
1,378,888	1,355,211	1,329,173	1,303,721	1,268,983	1,231,140	1,189,670	1,154,953
178,391	177,814	174,147	169,014	162,258	155,399	148,536	142,305
12,115	12,311	12,353	12,307	12,315	12,309	12,276	12,109
2,114	2,050	1,993	1,858	1,816	1,789	1,753	1,696
1,571,508	1,547,386	1,517,666	1,486,900	1,445,372	1,400,637	1,352,235	1,311,063
13,746	13,900	15,110	14,924	14,773	14,947	14,562	14,535

</TABLE>

SELECTED FINANCIAL AND OPERATING DATA (continued)
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<TABLE>
<CAPTION>

<S>	1993 <C>	1992 <C>	1991 <C>
OPERATING REVENUES (IN THOUSANDS):			
Residential	$ 1,291,035	$ 1,128,396	$ 1,111,358
Commercial	1,354,130	1,285,681	1,243,067
Industrial	1,113,067	1,083,856	1,057,702
Other	41,399	39,504	37,861
Total retail	3,799,631	3,537,437	3,449,988
Sales for resale - non-affiliates	534,370	640,308	736,643
Sales for resale - affiliates	61,668	67,835	65,586
Total revenues from sales of electricity	4,395,669	4,245,580	4,252,217
Other revenues	55,512	51,856	49,211
Total	$ 4,451,181	$ 4,297,436	$ 4,301,428
KILOWATT-HOUR SALES (IN THOUSANDS):			
Residential	16,649,859	14,939,172	14,815,089
Commercial	18,278,508	17,260,614	16,885,833
Industrial	23,635,363	22,978,312	22,298,062
Other	460,801	436,144	429,016
Total retail	59,024,531	55,614,242	54,428,000
Sales for resale - non-affiliates	14,307,030	15,870,222	18,719,924
Sales for resale - affiliates	3,027,733	3,320,060	3,885,892
Total	76,359,294	74,804,524	77,033,816
AVERAGE REVENUE PER KILOWATT-HOUR (CENTS):			
Residential	7.75	7.55	7.50
Commercial	7.41	7.45	7.36
Industrial	4.71	4.72	4.74
Total retail	6.44	6.36	6.34

Sales for resale	3.44	3.69	3.55
Total sales	5.76	5.68	5.52
RESIDENTIAL AVERAGE ANNUAL KILOWATT-HOUR USE PER CUSTOMER	11,630	10,603	10,675
RESIDENTIAL AVERAGE ANNUAL REVENUE PER CUSTOMER	$ 901.79	$ 800.88	$ 800.78
PLANT NAMEPLATE CAPACITY RATINGS (YEAR-END) (MEGAWATTS)	13,759	14,076	14,076
MAXIMUM PEAK-HOUR DEMAND (MEGAWATTS) (NOTE):			
Winter	9,067	8,938	10,001
Summer	12,573	11,448	13,090
ANNUAL LOAD FACTOR (PERCENT)	58.5	60.5	55.2
PLANT AVAILABILITY (PERCENT):			
Fossil-steam	85.9	86.6	93.3
Nuclear	85.5	87.7	81.6
SOURCE OF ENERGY SUPPLY (PERCENT):			
Coal	62.1	61.4	63.6
Nuclear	16.2	17.0	15.3
Hydro	2.3	2.5	2.3
Oil and gas	0.2	*	*
Purchased power -			
From non-affiliates	10.2	12.2	10.3
From affiliates	9.0	6.9	8.5
Total	100.0	100.0	100.0
TOTAL FUEL ECONOMY DATA:			
BTU per net kilowatt-hour generated	9,912	9,900	9,960
Cost of fuel per million BTU (cents)	153.62	153.08	157.97
Average cost of fuel per net kilowatt-hour generated (cents)	1.52	1.52	1.57

</TABLE>

Note: As of 9/1/91, Georgia Power Company's sales to Oglethorpe Power Company are not included in Peak-Hour Demand

* Less than one-tenth of one percent.

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<TABLE>
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1990	1989	1988	1987	1986	1985	1984	1983
$ 1,109,165	$ 1,022,781	$ 979,047	$ 904,218	$ 874,231	$ 786,500	$ 754,163	$ 686,269
1,218,441	1,143,727	1,054,995	915,540	854,755	797,540	739,035	649,932
1,061,830	1,006,416	983,822	911,933	897,646	873,554	858,536	747,305
36,773	34,775	31,743	29,350	27,948	26,766	24,388	20,972
3,426,209	3,207,699	3,049,607	2,761,041	2,654,580	2,484,360	2,376,122	2,104,478
784,086	760,809	707,076	822,696	780,049	941,743	779,028	666,739
168,251	150,394	86,751	159,998	91,753	149,463	136,047	70,784
4,378,546	4,118,902	3,843,434	3,743,735	3,526,382	3,575,566	3,291,197	2,842,001
67,263	26,338	54,045	42,750	35,221	33,574	28,502	27,882
$ 4,445,809	$ 4,145,240	$ 3,897,479	$ 3,786,485	$ 3,561,603	$3,609,140	$3,319,699	$2,869,883
14,771,648	14,134,195	13,800,038	13,675,730	13,234,248	12,006,462	11,548,787	11,443,257
16,627,128	15,843,181	14,790,561	13,799,379	12,945,926	11,945,938	10,902,163	10,181,953
22,126,604	21,801,404	21,412,845	20,884,454	20,339,235	19,517,543	18,862,531	17,415,441
428,459	414,107	397,669	385,514	381,917	382,238	342,047	331,804
53,953,839	52,192,887	50,401,113	48,745,077	46,901,326	43,852,181	41,655,528	39,372,455
20,158,681	20,479,412	18,544,705	20,910,185	18,198,186	21,526,865	19,138,575	16,197,259
8,272,528	7,489,948	3,327,814	6,032,889	3,160,242	5,999,834	4,970,928	2,938,120
82,385,048	80,162,247	72,273,632	75,688,151	68,259,754	71,378,880	65,765,031	58,507,834
7.51	7.24	7.09	6.61	6.61	6.55	6.53	6.00
7.33	7.22	7.13	6.63	6.60	6.68	6.78	6.38
4.80	4.62	4.59	4.37	4.41	4.48	4.55	4.29
6.35	6.15	6.05	5.66	5.66	5.67	5.70	5.35
3.35	3.26	3.63	3.65	4.08	3.96	3.80	3.85
5.31	5.14	5.32	4.95	5.17	5.01	5.00	4.86

10,795	10,530	10,484	10,623	10,577	9,923	9,855	10,049
$ 810.56	$ 761.96	$ 743.82	$ 702.36	$ 698.72	$ 650.01	$ 643.53	$ 602.66
14,366	14,366	13,018	13,018	11,875	11,875	11,767	11,698
8,977	10,101	9,866	9,446	10,551	10,049	8,462	7,556
13,196	12,735	12,295	12,390	11,910	11,079	10,443	10,933
55.5	56.3	59.1	56.1	57.5	56.3	56.9	51.9
92.5	93.0	94.5	92.7	91.2	91.2	91.0	91.7
81.3	89.2	69.4	85.4	64.7	79.5	47.3	68.6
65.1	64.0	72.0	70.9	74.6	72.7	74.4	72.2
13.7	14.1	9.6	9.1	5.0	6.7	4.0	6.3
2.2	2.1	1.2	1.7	1.2	1.5	2.7	3.1
0.1	0.1	0.1	0.1	0.6	*	*	0.1
11.0	10.2	8.2	8.5	8.9	9.4	9.2	8.4
7.9	9.5	8.9	9.7	9.7	9.7	9.7	9.9
100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
9,939	10,020	9,969	9,932	10,016	10,089	10,002	10,100
166.22	164.27	166.28	168.81	175.81	178.11	184.63	179.92
1.65	1.65	1.66	1.68	1.76	1.80	1.85	1.82

</TABLE>