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2003 Annual Report

GEORGIA POWER
A SOUTHERN COMPANY

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CONTENTS

Georgia Power Company 2003 Annual Report

SUMMARY

	2003	2002	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$4,914**	$4,822	1.9
Operating expenses	**$3,690**	$3,618	2.0
Net income after dividends on preferred stock	**$631**	$618	2.1
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**75,018**	75,432	(0.5)
Sales for resale – non-affiliates	**8,836**	8,069	9.5
Sales for resale – affiliates	**5,844**	3,963	47.5
Total	**89,698**	87,464	2.6
Customers served at year-end *(in thousands)*	**2,038**	1,997	2.1
Peak-hour demand *(in megawatts)*	**14,826**	14,597	1.6
Capitalization Ratios *(percent)*:			
Common stock equity	**49.0**	52.2	
Preferred stock	**0.2**	0.2	
Mandatorily redeemable preferred securities	**10.2**	11.1	
Long-term debt	**40.6**	36.5	
Return on Average Common Equity *(percent)*	**14.05**	13.99	
Ratio of Earnings to Fixed Charges *(times)*	**5.01**	5.07	

Georgia Power's strong financial and operational performance in 2003 resulted in an outstanding year for the company. Reliability at our plants was at an all-time high. We led the industry in customer satisfaction. And we continued to expand our transmission and distribution infrastructure to meet the energy demands of our growing customer base.

Georgia Power's earnings for 2003 totaled $631 million, a $13 million, or 2.1 percent increase, from 2002. We earned a 14.05 percent total company return on average common equity during 2003. Georgia Power had a net plant in service investment of $11.3 billion at the end of the year, with total assets of $14.8 billion. Operating revenues for 2003 were $4.9 billion.

The company's solid financial performance occurred despite one of the mildest summers on record. The mercury reached 90 degrees in Atlanta on only seven days in 2003, reducing electricity sales to retail customers. However, continued customer growth, despite the weak economy, partially offset the weather's impact on earnings.

We're fortunate to live in a state that's attracting new people and businesses. Because of this growth, we increased our customer base last year by 41,280 to more than 2 million.

Our total sales of electricity climbed 2.6 percent in 2003 as we maintained an excellent reliability record. In fact, Georgia Power plants achieved a stellar peak season equivalent forced outage rate of 1.77 percent, surpassing our peak goal of 2.90 percent.

At the same time, we're being recognized nationally for how satisfied our customers are with the service we provide. For instance, for the fifth consecutive year, Southern Company, including Georgia Power, ranks No. 1 for overall customer satisfaction for electric service to midsize businesses in the South, according to a J. D. Power and Associates survey.

As testament to our reputation, several hundred Georgia Power employees headed to the Washington, D.C., area and North Carolina last fall to help restore widespread power outages in the wake of Hurricane Isabel. The storm left more than 4 million customers of utilities in those areas without power. Our employees continue to receive accolades for their professionalism and productivity.

Georgia Power prospered last year because we succeeded at managing the fundamentals of our business – generating and supplying power to our customers – and we're offering our customers more and more services to meet their needs.

For example, more than 100,000 customers have signed up for e-Bill, a service launched in 2001 that offers customers the ability to receive and pay their utility bills online through our Internet site. When customers requested more options for how they purchase energy, we introduced FlatBill statewide in 2002. The fixed-bill pricing plan was recognized last year with a 2003 Platts Global Energy Award for "Marketing Campaign of the Year."

As we run our business and take care of our customers, we're making great strides in minimizing our impact on the environment.

Last year, we completed a four-year, $800 million effort to retrofit power plants with various environmental control systems. The work included installing selective catalytic reduction systems on seven units to dramatically reduce emissions of nitrogen oxides (NOx), which contribute to the formation of ozone. The new controls will reduce NOx emissions by about 50 percent annually from 1990 levels, which will help the state comply with federal ozone standards.

The company's former president and CEO, David Ratcliffe, was named Diversity CEO of the Year last year as part of the Georgia Minority Business Awards. Georgia Power also was named Corporation of the Year, and David was named Executive of the Year at the Georgia Minority Supplier Development Council's Business Opportunity Expo.

Supplier diversity is a key goal for our company. In fact, we're committed to becoming a role model for supplier diversity, so it's gratifying to receive this recognition. Last year, we spent $133 million, or 10.5 percent of our total procurement dollars, excluding fuel, with minority- and female-owned businesses. We surpassed our goal of 9 percent. Our goal for 2004 is 11.25 percent.

As the company's new CEO succeeding Mr. Ratcliffe, I realize I have big shoes to fill, but I look forward to the challenge. Growth in the area and the increasing energy needs of our customers have made it important for us to keep pace by expanding our electricity infrastructure and the services we offer our customers.

In 2004, we'll take the steps necessary to prepare for the future and ensure that our customers continue to receive reliable, cost-effective electricity for many years to come.

Sincerely,

Michael D. Garrett
March 19, 2004

MANAGEMENT'S REPORT
Georgia Power Company 2003 Annual Report

The management of Georgia Power Company has prepared -- and is responsible for -- the financial statements and related information included in this report. These statements were prepared in accordance with accounting principles generally accepted in the United States 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 accounting records reflect only authorized transactions of the Company. Limitations exist in any system of internal controls, however, based upon recognition that the cost of the system should not exceed its benefits. The Company believes its system of internal accounting controls maintains an appropriate cost/benefit relationship.

The Company's internal accounting controls are 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.

Southern Company's audit committee of its board of directors, composed of four independent directors, provides a broad overview of management's financial reporting and control functions. Additionally, the Controls and Compliance Committee of the Company's board of directors, composed of a minimum of three outside directors, meets periodically with management, the internal auditors, and the independent public accountants to discuss auditing, internal controls, and compliance matters. The internal auditors and independent public accountants have access to the members of these committees 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, in all material respects, the financial position, results of operations and cash flows of Georgia Power Company in conformity with accounting principles generally accepted in the United States.

David M. Ratcliffe
Chief Executive Officer

Michael D. Garrett
President

C. B. Harreld
Executive Vice President, Treasurer, and Chief Financial Officer
March 1, 2004

INDEPENDENT AUDITORS' REPORT

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (a wholly owned subsidiary of Southern Company) as of December 31, 2003 and 2002, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows of the years then ended. These financial statements are the responsibility of Georgia Power Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The financial statements of Georgia Power Company for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements and included an explanatory paragraph that described a change in the method of accounting for derivative instruments and hedging activities in their report dated February 13, 2002.

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

In our opinion, the financial statements (pages 23 to 49) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, in 2003 Georgia Power Company changed its method of accounting for asset retirement obligations.

Deloitte & Touche LLP

Atlanta, Georgia
March 1, 2004

THE FOLLOWING REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED IN CONNECTION WITH THE COMPANY'S 2001 ANNUAL REPORT AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

To Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (a Georgia corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2001 and 2000, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the United States. 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 16-36) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, Georgia Power Company changed its method of accounting for derivative instruments and hedging activities.

Arthur Andersen LLP

Atlanta, Georgia
February 13, 2002

OVERVIEW OF EARNINGS AND BUSINESS ACTIVITIES

Earnings

Georgia Power Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002. Operating income increased in 2003 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the increase. The Company's 2002 earnings totaled $618 million, representing an $8 million (1.2 percent) increase over 2001. Operating income declined slightly in 2002. Lower retail and wholesale revenues, higher other operating and maintenance expenses and increased purchased power capacity expenses were significantly offset by lower depreciation and amortization expense as a result of a Georgia Public Service Commission (GPSC) retail rate order effective January 2002. The increase in net income for 2002 resulted from lower financing costs and a lower effective tax rate due to the realization of certain state tax credits. The Company's 2001 earnings totaled $610 million, representing a $51 million (9.1 percent) increase over 2000. Operating income was lower in 2001 compared to 2000 due to the impact of mild weather on retail revenues; however, overall net income improved due to lower financing costs and non-operating expenses and a lower effective tax rate resulting from various factors including property donations and positive resolution of outstanding tax issues.

Business Activities

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Several factors affect the opportunities, challenges and risk of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover costs related to growing demand and increasingly strict environmental standards. Future earnings for the electricity business in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the service area.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2003	**2003**	2002	2001
		(in millions)		
Operating revenues	**$4,914**	**$ 92**	$(144)	$ 95
Fuel	**1,104**	**101**	64	(79)
Purchased power	**776**	**92**	(87)	175
Other operation and maintenance	**1,247**	**(78)**	85	41
Depreciation and amortization	**350**	**(54)**	(197)	(19)
Taxes other than income taxes	**213**	**11**	(1)	(1)
Total operating expenses	**3,690**	**72**	(136)	117
Operating income	**1,224**	**20**	(8)	(22)
Other income and (expense)	**(227)**	**2**	9	76
Less - Income taxes	**366**	**9**	(7)	3
Net income	**$ 631**	**$ 13**	$ 8	$ 51

Revenues

Operating revenues in 2003, 2002, and 2001 and the percent of change from the prior year are as follows:

	Amount		
	2003	2002	2001
		(in millions)	
Retail – prior year	**$4,288**	$4,349	$4,317
Change in -			
Base rates	**-**	(118)	-
Sales growth and other	**30**	2	90
Weather	**(66)**	82	(107)
Fuel cost recovery and other	**58**	(27)	49
Retail – current year	**4,310**	4,288	4,349
Sales for resale -			
Non-affiliates	**260**	271	366
Affiliates	**175**	98	100
Total sales for resale	**435**	369	466
Other operating revenues	**169**	165	151
Total operating revenues	**$4,914**	$4,822	$4,966
Percent change	**1.9%**	(2.9)%	2.0%

Retail base revenues of $3.0 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures in 2003 and the sluggish economy. Residential kilowatt-hour (KWH) sales decreased by 1.7 percent. Retail base revenues of $3.1 billion in 2002 decreased by $34 million (1.1 percent) from 2001 primarily due to a base rate reduction effective January 2002 under the GPSC retail rate order and generally lower prices to large business customers. This decrease was partially offset by a 10.1 percent increase in residential KWH sales due to warmer weather. Retail base revenues of $3.1 billion in 2001 decreased $17 million (0.5 percent) from 2000, primarily due to a 2.5 percent decrease in retail KWH sales from the prior year. Milder-than-normal weather and a slowdown in the economy contributed to the decline in such sales.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses -- including the fuel component of purchased energy -- and do not affect net income. As of December 31, 2003, the Company had $151 million in under-recovered fuel costs. On August 19, 2003, the GPSC issued an order allowing the Company to increase customer fuel rates to recover existing under-recovered deferred fuel costs. See Note 3 to the financial statements under "Fuel Cost Recovery" for further information regarding this order.

Wholesale revenues from sales to non-affiliated utilities were:

	2003	2002	2001
		(in millions)	
Unit power sales --			
Capacity	**$ 34**	$ 34	$ 26
Energy	**31**	34	35
Other power sales --			
Capacity	**38**	41	72
Energy	**157**	162	233
Total	**$260**	$271	$366

Revenues from unit power contracts decreased slightly in 2003 due to decreased energy sales. Approximately 103 megawatts of capacity is scheduled to be sold annually through 2010. Revenues from other non-affiliated sales decreased $8 million (3.9 percent) in 2003, decreased $102 million (33.4 percent) in 2002 and increased $62 million in 2001 primarily due to fluctuations in off-system sale transactions that were generally offset by corresponding purchase transactions. These transactions had no significant effect on income. In 2002, revenues also decreased $37 million as a result of transferring Plant Dahlberg to Southern Power Company (Southern Power) in July 2001.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. In 2003, energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $4 million (2.4 percent) in 2003 primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenue from the rental of electric property of $4 million. See Note 3 to the financial statements under "Open Access Transmission

Tariff" for further information regarding the increase in the open access transmission tariff rate. Other operating revenues in 2002 increased $14 million (9.5 percent) primarily due to the collection of new late payment fees approved under the retail rate order effective January 2002 of $7 million and higher revenues from increased customer demand for outdoor lighting services of $5 million and the transmission of electricity of $3 million. Other operating revenues in 2001 decreased $9 million (5.3 percent) primarily due to lower gains on the sale of generating plant emission allowances, partially offset by increased revenues from the transmission of electricity and from the rental of electric equipment and property.

Energy Sales

KWH sales for 2003 and the percent change by year were as follows:

	KWH	Percent Change		
	2003	**2003**	2002	2001
	(in billions)			
Residential	**21.8**	**(1.7)%**	10.1%	(2.8)%
Commercial	**26.9**	**(0.1)**	1.7	3.4
Industrial	**25.7**	**(0.1)**	1.5	(8.0)
Other	**0.6**	**0.4**	1.7	2.5
Total retail	**75.0**	**(0.5)**	4.0	(2.5)
Sales for resale -				
Non-affiliates	**8.9**	**9.5**	(0.5)	25.5
Affiliates	**5.8**	**47.5**	26.5	28.7
Total sales for resale	**14.7**	**22.0**	7.0	26.3
Total sales	**89.7**	**2.6**	4.4	0.5

Residential KWH sales decreased 1.7 percent in 2003 due to the effect of the milder summer weather despite the 2 percent increase in residential customers. Commercial KWH sales declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Residential KWH sales increased 10.1 percent in 2002 due to the effect of the warmer weather. Commercial and industrial KWH sales increased 1.7 percent and 1.5 percent, respectively, due to corresponding increases of 2.6 percent and 2.4 percent, respectively, in customers. Residential KWH sales decreased 2.8 percent in 2001 due to milder-than-normal weather. Commercial KWH sales increased 3.4 percent due to an increase in customers, while industrial KWH sales decreased 8.0 percent due to an economic slowdown. Retail sales growth assuming normal weather is expected to be 1.6 percent on average from 2004 to 2013.

Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by system load, the unit cost of fuel consumed, and the availability of hydro and nuclear generating units. The amount and sources of generation and the average cost of fuel per net kilowatt-hour generated were as follows:

	2003	2002	2001
Total generation (billions of KWH)	**73.1**	70.4	68.9
Sources of generation (percent) --			
Coal	**75.4**	77.4	74.9
Nuclear	**21.6**	21.1	23.2
Hydro	**2.7**	1.2	1.4
Oil and gas	**0.3**	0.3	0.5
Average cost of fuel per net KWH generated (cents) --	**1.46**	1.42	1.38
Average cost of purchased power per net KWH (cents) --	**4.03**	3.29	3.79

Fuel expense increased 10.1 percent in 2003 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003. Fuel expense increased 6.8 percent in 2002 due to a 2.2 percent increase in generation because of higher energy demands and a 2.9 percent higher average cost of fuel due to the higher cost of coal. In 2001, fuel expense decreased 7.7 percent due to a decrease in generation because of lower energy demands and a slightly lower average cost of fuel.

Purchased power expense increased $91 million (13.3 percent) in 2003 primarily due to $75 million of additional capacity expense associated with new purchased power contracts that went into effect in 2003 and 2002. Purchased power expense decreased $87 million (11.2 percent) in 2002 and increased $175 million (29.4 percent) in 2001 primarily due to fluctuations in off-system energy purchases used to meet off-system sales commitments. The 2002 decrease in energy purchases was partially offset by a $43 million increase in capacity expense associated with new purchased power contracts.

In 2003, other operation and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million. In 2002, other operation and maintenance expenses increased $85 million (6.8 percent) due to the timing of generating plant maintenance of $44 million and transmission maintenance of $17 million, and increased property insurance expense of $5 million. In 2001, other operation and maintenance expenses increased $41 million (3.4 percent) due to additional severance costs, increased scheduled generating plant maintenance, and higher uncollectible account expense.

Depreciation and amortization decreased $54 million in 2003 primarily as a result of lower regulatory charges related to the inclusion of new certified purchased power costs in retail rates on a levelized basis as ordered by the GPSC. Depreciation and amortization decreased $197 million in 2002 primarily as a result of discontinuing accelerated depreciation, beginning amortization of the regulatory liability for accelerated cost recovery, and lowering the composite depreciation rates in January 2002 all in accordance with the retail rate order. Depreciation and amortization decreased $19 million in 2001 primarily due to lower accelerated amortization under the third year of a prior GPSC retail rate order. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002. Taxes other than income taxes remained relatively constant in 2002.

Interest income increased $12 million in 2003 when compared to the prior year due to interest on a favorable income tax settlement of $14.5 million. Interest income remained relatively constant in 2002.

Interest expense increased in 2003 primarily related to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. Interest expense decreased in 2002 and 2001 primarily due to lower interest rates that offset new financing costs. The Company refinanced or retired $665 million, $929 million, and $775 million of securities in 2003, 2002, and 2001, respectively. Interest capitalized decreased in 2003 and 2002 due to the transfer of three new generation projects to Southern Power in 2002 and 2001. Interest capitalized increased in 2001 during the construction phase of these new projects. See Note 7 to the financial statements under "Construction Program" for additional information regarding the construction and subsequent transfer of these generation assets. Distributions on mandatorily redeemable preferred securities decreased in 2003 due to the redemption of securities in the second half of 2002 and increased in 2002 due to the issuance of additional securities while remaining unchanged in 2001.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are also based on 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 utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

Future Earnings Potential

General

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 including the Company's ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover costs related to growing demand and increasingly strict environmental standards.

Growth in energy sales is subject to a number of factors which include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the service area.

Industry Restructuring

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the GPSC under cost-based regulatory principles.

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992 (Energy Act). The Energy Act allowed independent power producers to access a utility's transmission network and sell electricity to other utilities.

Although the Energy Act does not provide for retail customer access, it was a major catalyst for restructuring and consolidations that took place within the utility industry. Numerous federal and state initiatives that promote wholesale and retail competition are in varying stages. Among other things, these initiatives allow retail customers in some states to choose their electricity provider. Some states have approved initiatives that result in a separation of the ownership and/or operation of generating facilities from the ownership and/or operation of transmission and distribution facilities. While various restructuring and competition initiatives have been discussed in Georgia, none have been enacted. Enactment could require numerous issues to be resolved, including significant ones relating to recovery of any stranded investments, full cost recovery of energy produced, and other issues related to the energy crisis that occurred in California, as well as the August 2003 power outage in the Northeast. The Company does compete with other electric suppliers within the state. In Georgia, most new retail customers with at least 900 kilowatts of connected load may choose their electricity supplier.

Since 2001, merchant energy companies and traditional electric utilities with significant energy marketing and trading activities have come under severe financial pressures. Many of these companies have completely exited or drastically reduced all energy marketing and trading activities and sold foreign and domestic electric infrastructure assets. The Company has not experienced any material financial impact regarding its limited energy trading operations through Southern Company Services (SCS).

Continuing to be a low-cost producer could provide opportunities to increase the size and profitability in markets that evolve with changing regulation and competition. Conversely, future regulatory changes could adversely affect the Company's growth, and if the Company does not remain a low-cost producer and provide quality service, then energy sales growth could be limited, and this could significantly erode earnings.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action against the Company alleging the Company had violated the New Source Review (NSR) provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The action against the Company has been stayed since the spring of 2001 during the appeal of a very similar NSR action against the Tennessee Valley Authority before the U.S. Court of Appeals for the Eleventh Circuit. The Eleventh Circuit appeal was decided on September 16, 2003, and, on February 13, 2004, the EPA petitioned the U.S. Supreme Court to review the Eleventh Circuit's decision. At this time, no party to the Company's action, which was administratively closed two years ago, has asked the court to reopen that case. See Note 3 to the financial statements under "New Source Review Actions" for additional information.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. The December 2002 revisions included changes to the regulatory exclusions and the methods of calculating emissions increases. The October 2003 regulations clarified the scope of the existing Routine Maintenance Repair and Replacement exclusion. A coalition of states and environmental organizations filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. On December 24, 2003, the Court of Appeals granted a stay of the October 2003 revisions pending its review of the rules, and ordered that its review would be conducted on an expedited basis. In January 2004, the Bush Administration announced that it would continue to enforce the existing rules until the courts resolve legal challenges to the EPA's revised NSR regulations. In any event, the final regulations must be adopted by the State of Georgia in order to apply to the Company's facilities.

The effect of these final regulations and the related legal challenges cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day. An adverse outcome in this matter could require substantial capital expenditures and additional operation and maintenance expenses that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

On December 30, 2002, the Sierra Club, Physicians for Social Responsibility, Georgia ForestWatch, and one individual filed a civil suit in the U.S. District Court in Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. The civil action requests injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. This case is currently scheduled for trial during the summer of 2004. See Note 3 to the financial statements under "Plant Wansley Environmental Litigation" for additional information.

While the Company believes that it has complied with applicable laws and regulations, an adverse outcome could require payment of substantial penalties. The final outcome of this matter cannot now be determined.

Environmental Statutes and Regulations

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these environmental requirements will involve significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Environmental costs that are known and estimable at this time are included in capital expenditures under "Capital Requirements and Contractual Obligations." There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for the Company. The Title IV acid rain provisions of the Clean Air Act, for example, required significant reductions in sulfur dioxide and nitrogen oxide emissions. Title IV compliance was effective in 2000 and associated construction expenditures totaled approximately $206 million. Some of these expenditures also assisted the Company in complying with nitrogen oxide emission reduction requirements under Title I of the Clean Air Act, which were designed to address one-hour ozone nonattainment problems in Atlanta, Georgia. The State of Georgia adopted regulations that required additional nitrogen oxide emission reductions from May through September of each year at plants in and/or near those nonattainment areas. Seven generating plants in the Atlanta area are currently subject to those requirements, the most recent of which went into effect in 2003. Construction expenditures for compliance with the nitrogen oxide emission reduction requirements are estimated to be $698 million, of which $17 million remains to be spent.

On September 26, 2003, the EPA published a final rule effective January 1, 2004 reclassifying the Atlanta area from a "serious" to a "severe" nonattainment area for the one-hour ozone air quality standard under Title I of the Clean Air Act. The attainment deadline is to be as expeditious as practicable but not later than November 15, 2005. If the Atlanta area fails to comply with the one-hour ozone standard by the deadline, all major sources of nitrogen oxides and volatile organic compounds located in the nonattainment area, including the Company's plants McDonough and Yates, could be subject to payment of annual emissions fees for nitrogen oxides emitted above 80 percent of the baseline period. The baseline period is expected to be the calendar year 2005. Based on average emissions at these units over the past three years, such fees could reach $23 million annually. The final outcome of this matter will depend on the baseline period selected and the development, approval, and implementation of applicable regulations including new regulations for the eight-hour ozone air quality standard.

To help ozone nonattainment areas attain the one-hour ozone standard, the EPA issued regional nitrogen oxide reduction rules in 1998. Those rules required 21 states, including Georgia, to reduce and cap nitrogen oxide emissions from power plants and other large industrial sources. As a result of litigation challenging the rule, the courts required the EPA to complete a separate rulemaking before the requirements can be applied in Georgia. The final EPA rules have not been issued in Georgia. The impact of this rule on the Company will depend on the form in which it is finalized and cannot be determined at this time.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. These revisions made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court found the EPA's implementation program for the new eight-hour ozone standard unlawful and remanded it to the EPA for further rulemaking. During 2003, the EPA proposed implementation rules designed to address the court's concerns. The EPA plans to designate areas as attainment or nonattainment with the new eight-hour ozone standard in April 2004 and with the new fine particulate matter standard by the end of 2004. These designations will be based on air quality data for 2001 through 2003. Several areas within the Company's service area are likely to be designated nonattainment under these standards. State implementation plans (SIPs), including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. Those SIPs could require reductions in sulfur dioxide emissions and could require further reductions in nitrogen oxide emissions from power plants. If so, reductions could be required sometime after 2007. The impact of any new standards will depend on the development and implementation of applicable regulations and cannot be determined at this time.

In January 2004, the EPA issued a proposed Interstate Air Quality Rule to address interstate transport of ozone and fine particles. This proposed rule would require additional year-round sulfur dioxide and nitrogen oxide emission reductions from power plants in the eastern United States in two phases – in 2010 and 2015. The EPA currently plans to finalize this rule by 2005. If finalized, the rule could modify or supplant other SIP requirements for attainment of the fine particulate matter standard and the eight-hour ozone standard. The impact of this rule on the Company will depend upon the specific requirements of the final rule and cannot be determined at this time.

Further reductions in sulfur dioxide and nitrogen oxides could also be required under the EPA's Regional Haze rules. The Regional Haze rules require states to establish Best Available Retrofit Technology (BART) standards for certain sources that contribute to regional haze. The Company has a number of plants that could be subject to these rules. The EPA's regional haze program calls for states to submit SIPs in 2007. The SIPs must contain emission reduction strategies for implementing BART and achieving progress toward the Clean Air Act's visibility improvement goal. In 2002, however, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the BART provisions of the federal Regional Haze rules to the EPA for further rulemaking. The EPA has entered into an agreement that requires proposed revised rules in April 2004 and final rules in 2005. Because new BART rules have not been developed and state visibility assessments for progress are only beginning, it is not possible to determine the effect of these rules on the Company at this time.

The EPA's Compliance Assurance Monitoring (CAM) regulations under Title V of the Clean Air Act require that monitoring be performed to ensure compliance with emissions limitations on an ongoing basis. In 2004 and 2005, a number of the Company's plants will likely be subject to CAM requirements for at least one pollutant, in most cases, particulate matter. The Company is in the process of developing CAM plans. Because the plans are still under development, the Company cannot determine the costs associated with implementation of the CAM regulations. Actual ongoing monitoring costs are expensed as incurred and are not material for any year presented.

In January 2004, the EPA issued proposed rules regulating mercury emissions from electric utility boilers. The proposal solicits comments on two possible approaches for the new regulations – a Maximum Achievable Control Technology approach and a cap-and-trade approach. Either approach would require significant reductions in mercury emissions from Company facilities. The regulations are scheduled to be finalized by the end of 2004, and compliance could be required as early as 2007. Because the regulations have not been finalized, the impact on the Company cannot be determined at this time.

Several major bills to amend the Clean Air Act to impose more stringent emissions limitations on power plants have been proposed by Congress. Three of these, the Bush Administration's Clear Skies Act, the Clean Power Act of 2003, and the Clean Air Planning Act of 2003, propose to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury. The latter two bills also propose to limit emissions of carbon dioxide. The cost impacts of such legislation would depend upon the specific requirements enacted and cannot be determined at this time.

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes international constraints on the emissions of greenhouse gases. The Bush Administration does not support U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and has instead announced a new voluntary climate initiative, known as Climate VISION, which seeks an 18 percent reduction by 2012 in the rate of greenhouse gas emissions relative to the dollar value of the U.S. economy. Through Southern Company, the Company is involved in a voluntary electric utility industry sector climate change initiative in partnership with the government. The electric utility sector has pledged to reduce its greenhouse gas intensity 3 to 5 percent over the next decade, and is in the process of developing a memorandum of understanding with the Department of Energy (DOE) to cover this voluntary program.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up and monitor known sites. Amounts expensed for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for a portion or all required cleanup costs for additional sites that may require environmental remediation. Under GPSC ratemaking provisions, $21 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs. See Note 3 to the financial statements under "Potentially Responsible Party Status" for information regarding the Company's potentially responsible party status at sites in Georgia.

Under the Clean Water Act, the EPA has been developing new rules aimed at reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. On February 16, 2004, the EPA finalized these rules. These rules will require numerous biological studies, and, perhaps, retrofits to some intake structures at existing power plants. The impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation.

The Company is also planning to install cooling towers at some of its facilities to cool water prior to discharge under the Clean Water Act. Cooling towers for two plants near Atlanta are scheduled for completion in 2004 and 2008 at an estimated total of $160 million, of which $90 million remains to be spent. Also, the Company is conducting a study of the aquatic environment at another facility to determine if additional controls are necessary.

In addition, under the Clean Water Act, the EPA and the State of Georgia Environmental Protection Division (EPD) are developing total maximum daily loads (TMDLs) for certain impaired waters. Establishment of maximum loads by the EPA or EPD may result in lowering permit limits for various pollutants and a requirement to take additional measures to control non-point source pollution (e.g., storm water runoff) at facilities that discharge into waters for which TMDLs are established. Because the effect on the Company will depend on the actual TMDLs and permit limitations established by the implementing agency, it is not possible to determine the effect on the Company at this time.

Several major pieces of environmental legislation are periodically considered for reauthorization or amendment by Congress. These include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with possible additional federal or state legislation or regulations related to global climate change, electromagnetic fields, or other environmental and health concerns could also significantly affect the Company. The impact of any new legislation, changes to existing legislation, or environmental regulations could affect many areas of the Company's operations.

The full impact of any such changes cannot, however, be determined at this time.

FERC Matters

Transmission

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule (Order 2000) on Regional Transmission Organizations (RTOs). Order 2000 encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Through Southern Company, the Company worked with a number of utilities in the Southeast to develop a for-profit RTO known as SeTrans. In 2002, the sponsors of SeTrans established a Stakeholder Advisory Committee to provide input into the development of the RTO from other sectors of the electric industry, as well as consumers. During the development of SeTrans, state regulatory authorities expressed concern over certain aspects of the FERC's policies regarding RTOs. In December 2003, the SeTrans sponsors announced that they would suspend work on SeTrans because the regulated utility participants, including the Company, had determined that it was highly unlikely to obtain support of both federal and state regulatory authorities. Any impact of the FERC's rule on the Company will depend on the regulatory reaction to the suspension of SeTrans and future developments, which cannot now be determined.

In July 2002, the FERC issued a notice of proposed rulemaking regarding open access transmission service and standard electricity market design. The proposal, if adopted, would among other things: (1) require transmission assets of jurisdictional utilities to be operated by an independent entity; (2) establish a standard market design; (3) establish a single type of transmission service that applies to all customers; (4) assert jurisdiction over the transmission component of bundled retail service; (5) establish a generation reserve margin; (6) establish bid caps for day ahead and spot energy markets; and (7) revise the FERC policy on the pricing of transmission expansions. Comments on the proposal were submitted by many interested parties, including Southern Company, and the FERC has indicated that it has revised certain aspects of the proposal in response to public comments. Proposed energy legislation would prohibit the FERC from issuing the final rule before October 31, 2006, and from making any final rule effective before December 31, 2006. That legislation has been approved by the House of Representatives but remains pending before the Senate. Passage of the legislation now appears in doubt. It is uncertain whether in the absence of legislation the FERC will move forward with any part or all of the proposed rule. Any impact of this proposal on the Company will depend on the form in which the final rule may be ultimately adopted. However, the Company's financial statements could be adversely affected by changes in the transmission regulatory structure in its regional power market.

Market-Based Rate Authority

The Company has obtained FERC approval to sell power to non-affiliates at market-based prices under specific contracts. Through SCS, as agent, the Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. In November 2001, the FERC modified the test it uses to consider utilities' applications to charge market-based rates and adopted a new test called the Supply Margin Assessment (SMA). The FERC applied the SMA to several utilities, including Southern Company's retail operating companies, and found them to be "pivotal suppliers" in their control area market and ordered the implementation of several mitigation measures. SCS, on behalf of the Company and the other retail operating companies, sought rehearing of the FERC order and the FERC delayed implementation of certain mitigation measures. SCS, on behalf of the Company and the other retail operating companies, submitted comments to the FERC in 2002 regarding these issues. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. The Company anticipates that the FERC will address the requests for rehearing in the near future. Regardless of the outcome of the SMA proposal, the FERC retains the ability to modify or withdraw the authorization for any seller to sell at market-based rates, if it determines that the underlying conditions for having such authority are no longer applicable. The final outcome of this matter will depend on the form in which the SMA test and mitigation measures rules may be ultimately adopted and cannot be determined at this time.

Purchased power agreements (PPAs) by the Company and Savannah Electric for Southern Power's Plant McIntosh capacity were certified by the GPSC in December 2002 after a competitive bidding process. In April 2003, Southern Power applied for FERC approval of the PPAs. Interveners have made filings in opposition of the FERC's acceptance of the PPAs, alleging that the PPAs do not meet the applicable standards for market-based rates between alliliates. In July 2003, the FERC accepted the PPAs to become effective as scheduled on June 1, 2005, subject to refund, and ordered that hearings be held. For additional information, see Note 3 to the financial statements under "FERC Matters."

Other Matters

The Company is currently operating under a GPSC approved three-year retail rate order ending December 31, 2004. Under the terms of the order, earnings are evaluated annually against a retail return on common equity range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return are applied to rate refunds with the remaining one-third retained by the Company. The Company is required to file a general rate case on July 1, 2004, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

The Company has entered into various long-term PPAs which will result in higher capacity and operating and maintenance payments in future years. These agreements have been certified by the GPSC under Georgia's Integrated Resource Plan statute. Once certified, these costs are recoverable in rates under the statute. See Notes 3 and 7 to the financial statements under "Retail Rate Orders" and "Fuel and Purchased Power Commitments," respectively, for additional information.

On December 24, 2002, the GPSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program effective January 1, 2003. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. The order limits the program in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery mechanism. Annual net financial gains from the hedging program will be shared with the retail customers receiving 75 percent and the Company retaining 25 percent of the net gains. There were no net gains in 2003.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $54 million, $59 million, and $60 million in 2003, 2002, and 2001, respectively. Future pension income is dependent on several factors including trust earnings and changes to the plan. The decline in pension income is expected to continue and to become an expense by as early as 2007. Postretirement benefit costs for the Company were $41 million, $43 million and $43 million in 2003, 2002, and 2001, respectively, and are expected to trend upward. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income and postretirement benefit costs are a component of the regulated rates and generally do not have a significant long-term effect on net income. For additional information, see Note 2 to the financial statements.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act introduces a prescription drug benefit for Medicare-eligible retirees starting in 2006, as well as a federal subsidy to plan sponsors like the Company that provide prescription drug benefits. In accordance with FASB Staff Position No. 106-1, the Company has elected to defer recognizing the effects of the Medicare Act for its postretirement plans under FASB Statement No. 106, Employers' Accounting for Postretirement Benefits Other than Pension until authoritative guidance on accounting for the federal subsidy is issued or until a significant event occurs that would require remeasurement of the plans' assets and obligations. The Company anticipates that the benefits it pays after 2006 will be lower as a result of the Medicare Act; however, the retiree medical obligations and costs reported in Note 2 to the financial statements do not reflect these changes. The final accounting guidance could require changes to previously reported information.

Nuclear security legislation was recently introduced and considered in Congress both as a free-standing bill in the Senate and as a part of comprehensive energy legislation in a House-Senate Conference Report. Neither of the proposals has been enacted. The Nuclear Regulatory Commission (NRC) also has ordered additional security measures for licensees in 2003. The Company is in the process of implementation and must be in full compliance with these orders by October 29, 2004. The requirements of the latest orders will have an impact on the Company's nuclear power plants and result in increased operation and maintenance expenses as well as additional capital expenditures. The precise impact of the new requirements will depend upon the details of the implementation of the new requirements, which have not been finalized.

The Georgia General Assembly has recently adopted legislation that changes the law concerning condemnation of land for electric transmission lines. The legislation requires that a utility planning to construct or expand a transmission line hold public meetings in each county where the line would be located and that the utility attempt to negotiate a settlement with each affected property owner. The legislation also provides for the reconveyance of property interests that are condemned for a transmission line but are not used for that purpose within a specified number of years. The legislation, unless vetoed by Governor Perdue, will become effective on July 1, 2004.

The Company is involved in various matters being litigated, regulatory matters, and related issues that could affect future earnings. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has discussed the development and selection of the critical accounting policies and estimates described below with the Controls and Compliance Committee of the Company's Board of Directors and the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the GPSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of Statement No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines. However, adverse legislation and judicial or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See "Future Earnings Potential" and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in Internal Revenue Service interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the EPA, or the EPD.

New Accounting Standards

Prior to January 2003, the Company accrued for the ultimate cost of retiring most long-lived assets over the life of the related asset through depreciation expense. FASB Statement No. 143, Accounting for Asset Retirement Obligations, established new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, non-regulated companies are no longer permitted to continue accruing future retirement costs for long-lived assets that they do not have a legal obligation to retire. For additional information regarding the impact of adopting this standard effective January 1, 2003, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

FASB Statement No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, which further amends and clarifies the accounting and reporting for derivative instruments, became effective generally for financial instruments entered into or modified after June 30, 2003. Current interpretations of Statement No. 149 indicate that certain electricity forward transactions subject to unplanned netting -- including those typically referred to as "book outs" -- may only qualify as cash flow hedges if an entity can demonstrate that physical delivery or receipt of power occurred. The Company's forward electricity contracts continue to be exempt from fair value accounting requirements or to qualify as cash flow hedges, with the related gains and losses deferred in other comprehensive income. The implementation of Statement No. 149 did not have a material effect on the Company's financial statements.

In July 2003, the Emerging Issues Task Force (EITF) of the FASB issued EITF No. 03-11, which became effective on October 1, 2003. The standard addresses the reporting of realized gains and losses on derivative instruments and is being interpreted to require book outs to be recorded on a net basis in operating revenues. Adoption of this standard did not have a material impact on the Company's financial statements.

FASB Interpretation No. 46, Consolidation of Variable Interest Entities, which was originally issued in January 2003, requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. In December 2003, the FASB revised Interpretation No. 46 and deferred the effective date until March 31, 2004 for interests held in variable interest entities other than special purpose entities.

Current analysis indicates that the trusts established by the Company to issue preferred securities are variable interest entities under Interpretation No. 46, and that the Company is not the primary beneficiary of the trusts. If this conclusion is finalized, effective March 31, 2004, the trust assets and liabilities -- including the preferred securities issued by the trusts -- will be deconsolidated. The investments in the trusts and the loans from the trusts to the Company will be reflected as equity method investments and as long-term notes payable to affiliates, respectively, on the Balance Sheets. Based on December 31, 2003 values, this treatment would result in an increase of approximately $29 million to both total assets and liabilities. See Note 6 to the financial statements under "Mandatorily Redeemable Preferred Securities" for additional information.

In May 2003, the FASB issued Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, which requires classification of certain financial instruments within its scope, including shares that are mandatorily redeemable, as liabilities. Statement No. 150 was effective for financial instruments entered into or modified after May 31, 2003, and otherwise on July 1, 2003. In accordance with Statement No. 150, the Company's mandatorily redeemable preferred securities are reflected as liabilities on the Balance Sheets. The adoption of Statement No. 150 had no impact on the Statements of Income and Cash Flows.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Over the last several years, the Company's financial condition has remained stable with emphasis on cost control measures combined with significantly lower cost of capital, achieved through the refinancing and/or redemption of higher-cost long-term debt, preferred stock and preferred securities. The Company operated at high levels of reliability while achieving industry-leading customer satisfaction levels and continuing to have retail prices below the national average.

In 2003, gross utility plant additions were $743 million. These additions were primarily related to transmission and distribution facilities and the purchase of nuclear fuel and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities. The Statements of Cash Flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2003, 48.3 percent in 2002, and 47.7 percent in 2001. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company expects to meet future capital requirements primarily using funds generated from operating activities and equity funds from Southern Company and by the issuance of new debt securities, term loans, and short-term borrowings. The Company had $137 million of GPSC approved financing authority as of December 31, 2003. The Company used this remaining authority in February 2004. The type and timing of future financings will depend on market conditions and regulatory approval of additional financing authority. Recently, the Company has relied on the issuance of unsecured debt and preferred securities, in addition to unsecured pollution control bonds issued for its benefit by public authorities, to meet its long-term external financing requirements.

In February 2002, the Company defeased its first mortgage bond indenture and all related liens or encumbrances on the Company's property were discharged. As a result, the Company cannot issue any securities pursuant to this indenture. See "First Mortgage Bond Indenture" under Note 6 to the financial statements for additional information.

The Company obtains financing separately without credit support from any affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company. In accordance with the Public Utility Holding Company Act, most loans between affiliated companies must be approved in advance by the Securities and Exchange Commission (SEC).

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company had approximately $725 million of unused credit arrangements with banks at the beginning of 2004. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other Southern Company operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. At December 31, 2003, the Company had outstanding $137 million of commercial paper and no extendible commercial notes.

At the beginning of 2004, the Company had not used any of its available credit arrangements. Bank credit arrangements are as follows:

Total	Unused	Expires 2004
	(in millions)	
$725	$725	$725

All of these credit arrangements allow for the execution of term loans for an additional two year period.

Financing Activities

In 2003, the Company's financing costs increased due to the issuance of new debt during the year. New issues during 2001 through 2003 totaled $3.2 billion and retirement or repayment of higher-cost securities totaled $2.4 billion.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 2001 through 2003, as of year-end, were as follows:

	2003	2002	2001
Composite interest rate on long-term debt	**4.01%**	4.47%	4.26%
Composite preferred stock dividend rate	**4.60**	4.60	4.60
Composite preferred securities distribution rate	**6.35**	6.35	7.49

Subsequent to December 31, 2003, the Company has issued $550 million of new securities with the proceeds used primarily to retire higher coupon long-term debt and for construction and general corporate purposes.

Credit Rating Risk

The Company does not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are contracts that could require collateral -- but not accelerated payment -- in the event of a credit rating change to below investment grade. These contracts are primarily for physical electricity purchases and sales, fixed-price physical gas purchases, and agreements covering interest rate swaps. At December 31, 2003, the maximum potential collateral requirements were approximately $227 million. At December 31, 2003, there were no material collateral requirements for the gas purchase contracts or other financial instrument agreements.

Market Price Risk

Due to cost-based regulations the Company has limited exposure to market volatility in interest rates, commodity fuel prices and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

To mitigate the Company's exposure to interest rates, the Company has entered into interest rate swaps that were designed as cash flow hedges of variable rate debt or anticipated debt issuances. At December 31, 2003 the Company had no variable long-term debt outstanding that had not been hedged. Therefore, there would be no effect on annualized interest expense if the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt. The Company is not aware of any facts or circumstances that would significantly affect such exposures in 2004. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases. Fair value of changes in derivative energy contracts and year-end valuations were as follows:

	Changes in Fair Value	
	2003	2002
	(in millions)	
Contracts beginning of year	**$0.1**	$0.4
Contracts realized or settled	**(0.4)**	0.9
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes	**3.5**	(1.2)
Contracts end of year	**$3.2**	$0.1

	Source of 2003 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in millions)		
Actively quoted	**$3.2**	$2.8	$0.4
External sources	**-**	-	-
Models and other methods	**-**	-	-
Contracts end of year	**$3.2**	$2.8	$0.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Gains and losses on derivative contracts that are not designated as hedges are recognized in the income statement as incurred. At December 31, 2003, the fair value of derivative energy contracts reflected in the financial statements was as follows:

	Amounts (in millions)
Regulatory liabilities, net	$3.2
Other comprehensive income	-
Net income	-
Total fair value	$3.2

Gains (losses) recognized in income in 2003, 2002, and 2001 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $747 million for 2004, $812 million for 2005, and $1,043 million for 2006. Environmental expenditures included in these amounts are $91 million, $113 million, and $316 million for 2004, 2005, and 2006, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

The Company has no generating plants under construction. However, construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet the environmental standards previously discussed, are ongoing.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Revenues and Fuel Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the GPSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest and distributions, preferred stock dividends, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

	2004	2005-2006	2007-2008	After 2008	Total
			(in millions)		
Long-term debt and preferred securities[a] --					
Principal	$ 2	$ 605	$ 306	$3,792	$ 4,705
Interest and distributions	211	409	363	3,885	4,868
Preferred stock dividends[b]	1	1	1	-	3
Operating leases	34	56	44	72	206
Purchase commitments[c] --					
Capital [d]	718	1,815	2,286	-	4,819
Coal and nuclear fuel	1,321	1,940	975	183	4,419
Natural gas[e]	156	297	280	1,625	2,358
Purchased power	293	828	852	2,573	4,546
Trusts[f] --					
Nuclear decommissioning	9	17	17	95	138
Postretirement benefits	9	21	-	-	30
DOE assessments	3	7	-	-	10
Total	$2,757	$5,996	$5,124	$12,225	$26,102

(a) All amounts are reflected based on final maturity dates. The Company will continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2004, as reflected in the Statements of Capitalization.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) The Company generally does not enter into non-cancelable commitments for other operation and maintenance expenditures. Total other operation and maintenance expenses for the last three years were $1.2 billion, $1.3 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2003, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on New York Mercantile future prices at December 31, 2003.

(f) Projections of nuclear decommissioning trust contributions are based on the current GPSC order which will be reevaluated in the Company's upcoming rate case and is subject to change. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension plans.

Cautionary Statement Regarding Forward-Looking Information

The Company's 2003 Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning the estimated construction and other expenditures and the Company's projections for energy sales and its goals for future generating capacity and earnings growth. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other comparable terminology. The Company cautions that there are various important factors that could cause actual results to differ materially from those indicated in the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- the impact of fluctuations in commodity prices, interest rates, and customer demand;
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and pending and future rate cases and negotiations;
- effects of and changes in political, legal, and economic conditions and developments in the United States, including the current soft economy;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar incidents or responses to such incidents;
- financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- weather and other natural phenomena;
- the direct or indirect effects on the Company's business resulting from the August 2003 power outage in the Northeast, or any similar incidents;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002, and 2001
Georgia Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Operating Revenues:			
Retail sales	**$4,309,972**	$4,288,097	$4,349,312
Sales for resale --			
Non-affiliates	**259,376**	270,678	366,085
Affiliates	**174,855**	98,323	99,411
Other revenues	**169,304**	165,362	150,986
Total operating revenues	**4,913,507**	4,822,460	4,965,794
Operating Expenses:			
Fuel	**1,103,963**	1,002,703	939,092
Purchased power --			
Non-affiliates	**258,621**	264,814	442,196
Affiliates	**516,944**	419,839	329,232
Other operations	**827,972**	848,436	810,043
Maintenance	**419,206**	476,962	430,413
Depreciation and amortization	**349,984**	403,507	600,631
Taxes other than income taxes	**212,827**	201,857	202,483
Total operating expenses	**3,689,517**	3,618,118	3,754,090
Operating Income	**1,223,990**	1,204,342	1,211,704
Other Income and (Expense):			
Allowance for equity funds used during construction	**10,752**	7,622	9,081
Interest income	**15,625**	3,857	4,264
Interest expense, net of amounts capitalized	**(182,583)**	(168,391)	(183,879)
Distributions on mandatorily redeemable preferred securities	**(59,675)**	(62,553)	(59,104)
Other income (expense), net	**(10,551)**	(9,259)	(7,719)
Total other income and (expense)	**(226,432)**	(228,724)	(237,357)
Earnings Before Income Taxes	**997,558**	975,618	974,347
Income taxes	**366,311**	357,319	363,599
Earnings Before Cumulative Effect of Accounting Change	**631,247**	618,299	610,748
Cumulative effect of accounting change-- less income taxes of $162	**-**	-	257
Net Income	**631,247**	618,299	611,005
Dividends on Preferred Stock	**670**	670	670
Net Income After Dividends on Preferred Stock	**$630,577**	$ 617,629	$ 610,335

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS

At December 31, 2003 and 2002
Georgia Power Company 2003 Annual Report

Assets	2003	2002
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 8,699**	$ 16,873
Receivables --		
Customer accounts receivable	**261,771**	302,995
Unbilled revenues	**117,327**	104,454
Under recovered regulatory clause revenues	**151,447**	117,580
Other accounts and notes receivable	**101,783**	122,585
Affiliated companies	**52,413**	40,501
Accumulated provision for uncollectible accounts	**(5,350)**	(5,825)
Fossil fuel stock, at average cost	**137,537**	120,048
Materials and supplies, at average cost	**271,040**	263,364
Vacation pay	**50,150**	53,677
Prepaid expenses	**46,157**	42,809
Other	**83**	436
Total current assets	**1,193,057**	1,179,497
Property, Plant, and Equipment:		
In service	**18,171,862**	17,222,661
Less accumulated provision for depreciation	**6,898,725**	6,533,412
	11,273,137	10,689,249
Nuclear fuel, at amortized cost	**129,056**	119,588
Construction work in progress	**341,783**	667,581
Total property, plant, and equipment	**11,743,976**	11,476,418
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**38,714**	36,167
Nuclear decommissioning trusts, at fair value	**423,319**	346,870
Other	**37,142**	28,612
Total other property and investments	**499,175**	411,649
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**509,887**	524,510
Prepaid pension costs	**405,164**	341,944
Unamortized debt issuance expense	**75,245**	67,362
Unamortized loss on reacquired debt	**177,707**	178,590
Other	**177,817**	162,686
Total deferred charges and other assets	**1,345,820**	1,275,092
Total Assets	**$14,782,028**	$14,342,656

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2003 and 2002
Georgia Power Company 2003 Annual Report

Liabilities and Stockholder's Equity	2003	2002
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 2,304**	$ 322,125
Notes payable	**137,277**	357,677
Accounts payable --		
Affiliated	**121,928**	135,260
Other	**238,069**	314,327
Customer deposits	**103,756**	94,859
Accrued taxes --		
Income taxes	**107,532**	20,245
Other	**166,892**	134,269
Accrued interest	**70,844**	59,608
Accrued vacation pay	**38,206**	42,442
Accrued compensation	**134,004**	130,893
Other	**105,234**	112,131
Total current liabilities	**1,226,046**	1,723,836
Long-term debt (See accompanying statements)	**3,762,333**	3,109,619
Mandatorily redeemable preferred securities (See accompanying statements)	**940,000**	940,000
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,303,085**	2,176,438
Deferred credits related to income taxes	**186,625**	208,410
Accumulated deferred investment tax credits	**312,506**	324,994
Employee benefit obligations	**295,788**	248,415
Asset retirement obligations	**475,585**	-
Other cost of removal obligations	**412,161**	800,117
Miscellaneous regulatory liabilities	**249,687**	331,241
Other	**63,432**	30,570
Total deferred credits and other liabilities	**4,298,869**	4,120,185
Total liabilities	**10,227,248**	9,893,640
Preferred stock (See accompanying statements)	**14,569**	14,569
Common stockholder's equity (See accompanying statements)	**4,540,211**	4,434,447
Total Liabilities and Stockholder's Equity	**$14,782,028**	$14,342,656
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2003 and 2002
Georgia Power Company 2003 Annual Report

	2003	2002	2003	2002
		(in thousands)		*(percent of total)*
Long-Term Debt:				
Long-term notes payable --				
5.25% to 5.75% due 2003	**$ -**	$ 320,000		
5.50% due December 1, 2005	**150,000**	150,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
5.125% to 6.875% due 2011-2047	**1,100,000**	745,000		
Variable rate (1.25% to 1.30% at 1/1/04)	**300,000**	-		
Total long-term notes payable	**2,000,000**	1,665,000		
Other long-term debt --				
Pollution control revenue bonds --				
Non-collateralized:				
1.20% to 5.45% due 2012-2034	**812,560**	751,760		
Variable rates (1.10% to 1.40% at 1/1/04) due 2011-2032	**873,330**	934,130		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**79,286**	81,411		
Unamortized debt premium (discount), net	**(539)**	(557)		
Total long-term debt (annual interest requirement -- $151.2 million)	**3,764,637**	3,431,744		
Less amount due within one year	**2,304**	322,125		
Long-term debt excluding amount due within one year	**3,762,333**	3,109,619	**40.6%**	36.5%
Mandatorily Redeemable Preferred Securities:				
$25 liquidation value --				
6.85% due 2029	**200,000**	200,000		
7.125% due 2042	**440,000**	440,000		
$1,000 liquidation value --				
4.875% due 2042*	**300,000**	300,000		
Total (annual distribution requirement -- $59.7 million)	**940,000**	940,000	**10.2**	11.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%	**14,569**	14,569		
Total (annual dividend requirement -- $0.7 million)	**14,569**	14,569	**0.2**	0.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 15,000,000 shares				
Outstanding - 7,761,500 shares	**344,250**	344,250		
Paid-in capital	**2,208,498**	2,156,040		
Premium on preferred stock	**40**	40		
Retained earnings	**2,010,297**	1,945,520		
Accumulated other comprehensive income (loss)	**(22,874)**	(11,403)		
Total common stockholder's equity	**4,540,211**	4,434,447	**49.0**	52.2
Total Capitalization	**$9,257,113**	$8,498,635	**100.0%**	100.0%

*The fixed rate thereafter is determined through remarketings for specific periods of varying length at floating rates determined by reference to 3-month LIBOR plus 3.05%.

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2003, 2002, and 2001
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	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)			
Balance at December 31, 2000	$344,250	$2,117,497	$40	$1,787,757	$ -	$4,249,544
Net income after dividends on preferred stock	-	-	-	610,335	-	610,335
Capital distributions to parent company	-	(160,000)	-	-	-	(160,000)
Capital contributions from parent company	-	225,060	-	-	-	225,060
Other comprehensive income (loss)	-	-	-	-	(153)	(153)
Cash dividends on common stock	-	-	-	(527,300)	-	(527,300)
Preferred stock transactions, net	-	-	-	(1)	-	(1)
Balance at December 31, 2001	344,250	2,182,557	40	1,870,791	(153)	4,397,485
Net income after dividends on preferred stock	-	-	-	617,629	-	617,629
Capital distributions to parent company	-	(200,000)	-	-	-	(200,000)
Capital contributions from parent company	-	173,483	-	-	-	173,483
Other comprehensive income (loss)	-	-	-	-	(11,250)	(11,250)
Cash dividends on common stock	-	-	-	(542,900)	-	(542,900)
Balance at December 31, 2002	**344,250**	**2,156,040**	**40**	**1,945,520**	**(11,403)**	**4,434,447**
Net income after dividends on preferred stock	-	-	-	**630,577**	-	**630,577**
Capital contributions from parent company	-	**52,458**	-	-	-	**52,458**
Other comprehensive income (loss)	-	-	-	-	**(11,471)**	**(11,471)**
Cash dividends on common stock	-	-	-	**(565,800)**	-	**(565,800)**
Balance at December 31, 2003	**$344,250**	**$2,208,498**	**$40**	**$2,010,297**	**$(22,874)**	**$4,540,211**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2003, 2002, and 2001
Georgia Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Net income after dividends on preferred stock	**$630,577**	$617,629	$610,335
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(5,133) and $(4,853), respectively	**(8,138)**	(7,693)	-
Cumulative effect of accounting change for qualifying hedges, net of tax of $180	-	-	286
Changes in fair value of qualifying hedges, net of tax of $(3,241), $(2,502) and $(277), respectively	**(5,550)**	(3,555)	(439)
Less: Reclassification adjustment for amounts included in net income, net of tax of $1,208 and $0, respectively	**2,217**	(2)	-
Total other comprehensive income (loss)	**(11,471)**	(11,250)	(153)
Comprehensive Income	**$619,106**	$606,379	$610,182

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2003, 2002, and 2001

Georgia Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Operating Activities:			
Net income	**$ 631,247**	$ 618,299	$ 611,005
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**390,201**	411,435	697,143
Deferred income taxes and investment tax credits, net	**230,221**	65,550	(48,329)
Pension, postretirement, and other employee benefits	**(29,118)**	(64,771)	(57,239)
Tax benefit of stock options	**11,649**	8,184	-
Settlement of interest rate hedges	**(11,250)**	860	-
Other, net	**2,768**	(50,282)	(43,458)
Changes in certain current assets and liabilities --			
Receivables, net	**(4,870)**	68,527	60,914
Fossil fuel stock	**(17,490)**	82,711	(103,296)
Materials and supplies	**(7,677)**	15,874	(15,628)
Other current assets	**(2,352)**	(18,880)	3,755
Accounts payable	**(49,598)**	64,902	(15,406)
Accrued taxes	**52,348**	(6,540)	18,392
Other current liabilities	**16,734**	16,166	(46,691)
Net cash provided from operating activities	**1,212,813**	1,212,035	1,061,162
Investing Activities:			
Gross property additions	**(742,810)**	(883,968)	(1,389,751)
Cost of removal net of salvage	**(28,265)**	(60,912)	(50,093)
Sales of property	**-**	387,212	534,760
Change in construction payables, net of joint owner portion	**(32,223)**	(7,411)	24,457
Other	**15,961**	34,580	20,862
Net cash used for investing activities	**(787,337)**	(530,499)	(859,765)
Financing Activities:			
Increase (decrease) in notes payable, net	**(220,400)**	(389,860)	43,698
Proceeds --			
Senior notes	**1,000,000**	500,000	600,000
Pollution control bonds	**-**	-	404,535
Mandatorily redeemable preferred securities	**-**	740,000	-
Capital contributions from parent company	**40,809**	165,299	225,060
Redemptions --			
First mortgage bonds	**-**	(1,860)	(390,140)
Pollution control bonds	**-**	(7,800)	(385,035)
Senior notes	**(665,000)**	(330,000)	-
Mandatorily redeemable preferred securities	**-**	(589,250)	-
Capital distributions to parent company	**-**	(200,000)	(160,000)
Payment of preferred stock dividends	**(696)**	(721)	(578)
Payment of common stock dividends	**(565,800)**	(542,900)	(527,300)
Other	**(22,563)**	(30,831)	(17,747)
Net cash used for financing activities	**(433,650)**	(687,923)	(207,507)
Net Change in Cash and Cash Equivalents	**(8,174)**	(6,387)	(6,110)
Cash and Cash Equivalents at Beginning of Period	**16,873**	23,260	29,370
Cash and Cash Equivalents at End of Period	**$ 8,699**	$ 16,873	$ 23,260
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $5,428, $9,368, and $38,331 capitalized, respectively)	**$215,463**	$203,707	$234,456
Income taxes (net of refunds)	**145,048**	326,698	381,995

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (Southern LINC), Southern Company Gas (Southern Company GAS), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). SCS, the system service company, provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Company GAS is a competitive retail natural gas marketer serving customers in Georgia. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and an energy services business. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both Southern Company and its subsidiaries are subject to the regulatory provisions of the PUHCA. The Company is also subject to regulation by the FERC and the Georgia Public Service Commission (GPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from these estimates.

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $303 million in 2003, $318 million in 2002, and $286 million in 2001. Cost allocation methodologies used by SCS are approved by the SEC and management believes they are reasonable.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management and technical services; administrative services including procurement, accounting, employee relations, and systems and procedures services; strategic planning and budgeting services; and other services with respect to business and operations. Costs for these services amounted to $289 million in 2003, $301 million in 2002, and $281 million in 2001.

The Company has an agreement with Southern Power under which the Company operates and maintains Southern Power owned plants Dahlberg, Franklin, and Wansley at cost. Reimbursements under these agreements with Southern Power amounted to $5.3 million in 2003, $5.3 million in 2002 and $1.0 million in 2001. These agreements arose from the transfer of certain generation facilities to Southern Power in 2001 and 2002. See Note 7 under "Construction Program" for additional information.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at Plant Branch. Fuel purchases totaled $91 million in 2003.

Effective June 2002, the Company entered into purchased power agreements (PPAs) with Southern Power for capacity and energy. Purchased power costs in 2003 and 2002 amounted to $203 million and $128 million, respectively. Additionally, the Company recorded $7 million and $12 million of prepaid capacity expenses included in Other Deferred Charges and Other Assets on the Balance Sheets at December 31, 2003 and 2002, respectively. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer. Under this agreement, the Company operates Plant Scherer and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $5.6 million in 2003 and $4.5 million in 2002. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $3.6 million in 2003 and $1.8 million in 2002. See Note 4 for additional information.

Also see Note 4 for information regarding the Company's ownership in and purchased power agreement with Southern Electric Generating Company.

The retail operating companies, including the Company, Southern Power, and Southern Company GAS may jointly enter into various types of wholesale energy, natural gas and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

Revenues and Fuel Costs

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Fuel costs are expensed as the fuel is used. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between recoverable fuel costs and amounts actually recovered in current rates.

The Company has a diversified base of customers. No single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged less than 1 percent of revenues despite an increase in customer bankruptcies.

Fuel expense includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $74 million in 2003, $71 million in 2002, and $75 million in 2001. The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in January 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into the year 2015. At Plant Hatch, an on-site dry storage facility became operational in 2000 and can be expanded to accommodate spent fuel through the life of the plant. Construction of an on-site dry storage facility at Plant Vogtle will begin in sufficient time to maintain pool full-core discharge capability.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. The assessment is being paid over a 15-year period, which began in 1993. 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 remaining liability at December 31, 2003 under this law to be approximately $10 million.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes and 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.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, Accounting for the Effects of Certain Types of Regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process. See Note 3 under "Retail Rate Orders" for additional information regarding the disposition of the regulatory liability for the accelerated cost recovery recorded under the retail rate order that ended December 31, 2001. Regulatory assets and (liabilities) reflected in the Company's Balance Sheets at December 31 relate to the following:

	2003	2002	Note
	(in millions)		
Deferred income tax charges	$ 510	$ 525	(a)
Loss on reacquired debt	178	179	(b)
Corporate building lease	54	54	(f)
Vacation pay	50	54	(d)
Postretirement benefits	23	25	(f)
DOE assessments	13	16	(c)
Generating plant outage costs	49	48	(f)
Other regulatory assets	1	7	(f)
Asset retirement obligation	(16)	-	(a)
Other cost of removal obligations	(412)	(800)	(a)
Accelerated cost recovery	(111)	(222)	(e)
Deferred income tax credits	(187)	(208)	(a)
Environmental remediation reserve	(21)	(21)	(f)
Purchased power	(77)	(63)	(f)
Other regulatory liabilities	(3)	(1)	(f)
Total	$ 51	$ (26)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income taxes are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2008.

(d) Recorded as earned by employees and recovered as paid, generally within one year.

(e) Amortized over a three-year period ending in 2004. See Note 3 under "Retail Rate Orders".

(f) Recorded and recovered or amortized as approved by the GPSC.

In the event that a portion of the Company's operations is no longer subject to the provisions of Statement No. 71, the Company would be required to write off related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and if impaired, write down the assets to their fair value. All regulatory assets and liabilities are to be reflected in rates.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.7 percent in 2003, 2.9 percent in 2002 and 3.3 percent in 2001. The composite depreciation rate was reduced because the lives of depreciable assets were extended effective January 2002 under the retail rate order. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost -- together with the cost of removal, less salvage -- is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

The Company recorded accelerated depreciation and amortization amounting to $91 million in 2001. Effective January 2002, the Company discontinued recording accelerated depreciation and amortization in accordance with a new retail rate order. Also, the Company was ordered to amortize $333 million -- the cumulative balance previously expensed -- equally over three years as a credit to amortization expense beginning January 2002. Additionally, effective January 2002 the Company was ordered to recognize new GPSC certified purchased power costs in rates evenly over the three years covered by the current retail rate order. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million and $63 million in 2003 and 2002, respectively. The Company will record a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Rate Orders" for additional information.

Asset Retirement Obligations and Other Costs of Removal

In accordance with regulatory requirements, prior to January 2003, the Company followed the industry practice of accruing for the ultimate cost of retiring most long-lived assets over the life of the related asset as part of the annual depreciation expense provision. In accordance with SEC requirements such amounts are reflected on the Balance Sheet as regulatory liabilities. Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement must be recorded in the period in which the liability is incurred. The costs must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, Statement No. 143 does not permit the continued accrual of future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. However, the Company has received guidance regarding accounting for the financial statement impacts of Statement No. 143 from the GPSC and will continue to recognize the accumulated removal costs for other obligations as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in plants Hatch and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2003 was $423 million. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, a liability for the removal of these facilities will not be recorded because no reasonable estimate can be made regarding the timing of any related retirements. The Company will continue to recognize in the Statements of Income the ultimate removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and those reflected in rates will be recognized as either a regulatory asset or liability in the Balance Sheets. The Company also revised the estimated cost to retire plants Hatch and Vogtle as a result of a new site-specific decommissioning study. The effect of the revision is a decrease of $24 million for the Statement No. 143 liability included in "Asset Retirement Obligations" with a corresponding decrease in property, plant and equipment. See "Nuclear Decommissioning" for further information on amounts included in rates.

Details of the asset retirement obligations included in the Balance Sheets are as follows:

	2003
	(in millions)
Balance beginning of year	$469
Liabilities incurred	-
Liabilities settled	-
Accretion	31
Cash flow revisions	(24)
Balance end of year	$476

If Statement No. 143 had been adopted on January 1, 2002, the pro-forma asset retirement obligations would have been $440 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial nuclear power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. The Company has established external trust funds to comply with the NRC's regulations. The funds set aside for decommissioning are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC and the GPSC as well as the Internal Revenue Service (IRS). Funds are invested in a tax efficient manner in a diversified mix of equity and fixed income securities. Equity securities typically range from 50 to 75 percent of the funds and fixed income securities from 25 to 50 percent. Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the GPSC. 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 Company has filed plans with the NRC to ensure that -- over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study as of December 31, 2003 and the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Site study year	2003	2003
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making the estimates.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the GPSC. The amounts expensed in 2003 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2003	$ 7	$ 2
Accumulated provisions:		
External trust funds, at fair value	$269	$154
Internal reserves	7	4
Total	$276	$158

Effective January 1, 2002, the GPSC decreased the annual decommissioning costs for ratemaking to $9 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2000. The estimates are $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent. The Company expects the GPSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The site study decommissioning costs reflect the license extension; however, the updated costs will not be reflected in rates until the GPSC issues a new rate order, which is not expected until December 2004.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated 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. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. All current construction costs should be included in retail rates. For the years 2003, 2002, and 2001, the average AFUDC rates were 5.51 percent, 3.79 percent, and 6.33 percent, respectively. AFUDC and interest capitalized, net of taxes, was less than 3.0 percent of net income after dividends on preferred stock for 2003, 2002, and 2001.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

The cost of replacements of property -- exclusive of minor items of property -- is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. In accordance with a GPSC order, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles range from 18 to 24 months for each unit. In accordance with the 2001 retail rate order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets that exceeds the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Cash and Cash Equivalents

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

Materials and Supplies

Generally, materials and supplies include the average 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.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. The Company accounts for its stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25. Accordingly, no compensation expense has been recognized because the exercise price of all options granted equaled the fair market value on the date of grant. When options are exercised, the Company receives a capital contribution from Southern Company equivalent to the related income tax benefit.

Financial Instruments

The Company uses derivative financial instruments to limit exposures to fluctuations in interest rates, the prices of certain fuel purchases and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value.

The Company and its affiliates, through SCS acting as their agent, enter into commodity related forward and option contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets or liabilities as appropriate until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the Statements of Income.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company's financial instruments for which the carrying amounts did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2003	**$3,685**	**$3,739**
At December 31, 2002	$3,350	$3,417
Preferred securities:		
At December 31, 2003	**$940**	**$976**
At December 31, 2002	$940	$961

The fair values for securities were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair values of marketable securities and qualifying cash flow hedges, and changes in additional minimum pension liabilities, net of income taxes less reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed pension plan covering substantially all employees. The plan is funded in accordance with Employee Retirement Income Security Act (ERISA) requirements. No contributions to the plan are expected for the year ending December 31, 2004. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the GPSC and the FERC. For the year ended December 31, 2004, such contributions are expected to total approximately $8.9 million.

The measurement date for plan assets and obligations is September 30 for each year. In 2002, the Company adopted several plan changes that had the effect of increasing benefits to both current and future retirees.

Pension Plans

The accumulated benefit obligation for the pension plan was $1.6 billion and $1.4 billion for 2003 and 2002, respectively. Changes during the year in the projected benefit obligations and in the fair value of plan assets were as follows:

	Projected Benefit Obligation	
	2003	2002
	(in millions)	
Balance at beginning of year	**$1,564**	$1,448
Service cost	**38**	36
Interest cost	**100**	107
Benefits paid	**(83)**	(74)
Amendments	**6**	33
Actuarial loss	**102**	14
Balance at end of year	**$1,727**	$1,564

	Plan Assets	
	2003	2002
	(in millions)	
Balance at beginning of year	**$1,838**	$2,044
Actual return on plan assets	**294**	(137)
Benefits paid	**(77)**	(69)
Balance at end of year	**$2,055**	$1,838

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the IRS revenue code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk.

	Plan Assets		
	Target	**2003**	2002
Domestic equity	37%	**37%**	35%
International equity	20	**20**	18
Global fixed income	26	**24**	25
Real estate	10	**11**	12
Private equity	7	**8**	10
Total	100%	**100%**	100%

The accrued pension costs recognized in the Balance Sheets were as follows:

	2003	2002
	(in millions)	
Funded status	**$328**	$274
Unrecognized transition amount	**(13)**	(17)
Unrecognized prior service cost	**118**	123
Unrecognized net actuarial gain (loss)	**(66)**	(78)
Prepaid pension asset, net	**367**	302
Portion included in employee benefit obligations	**38**	40
Total prepaid pension recognized in the Balance Sheets	**$405**	$342

In 2003 and 2002, amounts recognized in the Balance Sheets for accumulated other comprehensive income and intangible assets to record the minimum pension liability related to the nonqualified plans were $26 million and $15 million and $13 and $10 million, respectively.

Components of the plans' net periodic cost were as follows:

	2003	2002	2001
	(in millions)		
Service cost	**$ 38**	$ 36	$ 35
Interest cost	**100**	107	101
Expected return on plan assets	**(179)**	(179)	(168)
Recognized net gain	**(19)**	(27)	(31)
Net amortization	**6**	4	3
Net pension (income)	**$ (54)**	$ (59)	$ (60)

Postretirement Benefits

Changes during the year in the accumulated benefit obligations and in the fair value of plan assets were as follows:

	Accumulated Benefit Obligation	
	2003	2002
	(in millions)	
Balance at beginning of year	**$627**	$542
Service cost	**9**	8
Interest cost	**40**	40
Benefits paid	**(29)**	(27)
Actuarial loss	**76**	64
Balance at end of year	**$723**	$627

	Plan Assets	
	2003	2002
	(in millions)	
Balance at beginning of year	**$199**	$195
Actual return on plan assets	**36**	(18)
Employer contributions	**59**	49
Benefits paid	**(29)**	(27)
Balance at end of year	**$265**	$199

Postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the IRS revenue code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company minimizes the risk of large losses through the primary tool of diversification but also monitors and manages other aspects of risk.

	Plan Assets		
	Target	**2003**	2002
Domestic equity	43%	**42%**	38%
International equity	20	**21**	21
Global fixed income	33	**32**	35
Real estate	2	**3**	3
Private equity	2	**2**	3
Total	100%	**100%**	100%

The accrued postretirement costs recognized in the Balance Sheets were as follows:

	2003	2002
	(in millions)	
Funded status	**$(458)**	$(427)
Unrecognized transition obligation	**87**	96
Unrecognized prior service cost	**91**	98
Unrecognized net loss	**171**	106
Fourth quarter contributions	**9**	37
Employee benefit obligations recognized in the Balance Sheets	**$(100)**	$(90)

Components of the plans' net periodic cost were as follows:

	2003	2002	2001
	(in millions)		
Service cost	**$ 9**	$ 8	$ 9
Interest cost	**40**	40	39
Expected return on plan assets	**(24)**	(20)	(19)
Net amortization	**16**	15	14
Net postretirement cost	**$ 41**	$ 43	$ 43

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations and net periodic costs for the pension and postretirement benefit plans were:

	2003	2002	2001
Discount	**6.0%**	6.5%	7.5%
Annual salary increase	**3.8**	4.0	5.0
Long-term return on plan assets	**8.5**	8.5	8.5

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 8.25 percent for 2003, decreasing gradually to 5.25 percent through the year 2010 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2003 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$61
Service and interest costs	5	4

Employee Savings Plan

The Company sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2003, 2002, and 2001 were $18 million, $17 million, and $16 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such litigation against the Company cannot be predicted at this time; however, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Retail Rate Orders

In December 2001, the GPSC approved a three-year retail rate order for the Company ending December 31, 2004. Retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the order, earnings are evaluated against a retail return on common equity range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return are applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2003 and 2002 were within the common equity range.

Under a previous three-year order ending December 2001, the Company's earnings were evaluated against a retail return on common equity range of 10 percent to 12.5 percent. The order further provided for $85 million in each year, plus up to $50 million of any earnings above the 12.5 percent return during the second and third years, to be applied to accelerated amortization or depreciation of assets. Two-thirds of any additional earnings above the 12.5 percent return were applied to rate refunds, with the remaining one-third retained by the Company. Pursuant to the order, the Company recorded $333 million of accelerated amortization and interest thereon, which has been credited to a regulatory liability account as mandated by the GPSC.

Under the 2001 rate order, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the rate order required the Company to recognize capacity and operating and maintenance costs related to new GPSC certified purchased power contracts evenly in rates over a three - year period ending December 31, 2004.

The Company is required to file a general rate case on July 1, 2004, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

Under GPSC ratemaking provisions, $21 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs.

Retail Fuel Hedging Program

On December 24, 2002, the GPSC approved an order, effective in January 2003, allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. The order limits the program in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause. Annual net financial gains from the hedging program will be shared with the retail customers receiving 75 percent and the Company retaining 25 percent of the net gains.

Fuel Cost Recovery

In May 2003, the Company filed for a fuel cost recovery rate increase. On August 19, 2003, the GPSC issued an order approving a stipulation reached by the Company, the Consumers' Utility Counsel Division, Georgia Textile Manufacturers Association, Georgia Industrial Group and the staff of the GPSC. The stipulation allows the Company to increase fuel rates to recover existing under-recovered deferred fuel costs over the period of October 1, 2003 through March 31, 2005, as well as future projected fuel costs. The new fuel rate represents an average annual increase in rates paid by customers of approximately 1.6 percent.

Nuclear Performance Standards

The GPSC has adopted a nuclear performance standard for the Company's nuclear generating units under which the performance of plants Hatch and Vogtle is evaluated every three years. The performance standard is based on each unit's capacity factor as compared to the average of all comparable U.S. nuclear units operating at a capacity factor of 50 percent or higher during the three-year period of evaluation. Depending on the performance of the units, the Company could receive a monetary award or penalty under the performance standards criteria.

For the period 1999-2001, the Company's performance fell within the criteria prescribed by the GPSC. The Company will therefore not receive an award or penalty for the 1999-2001 performance periods.

Open Access Transmission Tariff

In October 2003, the FERC approved a new Open Access Transmission Tariff for the Company of $1.73 per kilowatt-month based on an 11.25 percent return on equity. The Company had requested a rate increase effective January 2002 based on a 13 percent return on equity. Pending FERC approval, the Company collected from customers based on the 13 percent return on equity, but recorded revenue subject to refund for amounts above the previously approved rate of $1.37 per kilowatt-month. As a result of the final settlement, a total of approximately $2.3 million was refunded to the Company's transmission customers in October 2003 and $7.2 million was recorded as revenue.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action against the Company alleging the Company had violated the New Source Review (NSR) provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants and violations of related state laws. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued to the Company a notice of violation related to the two plants mentioned previously. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation.

The action against the Company was stayed in the spring of 2001 during the appeal of a very similar NSR enforcement action against the Tennessee Valley Authority (TVA) before the U.S. Court of Appeals for the Eleventh Circuit. The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the final resolution of the TVA appeal could have a significant impact on the Company, the Company has been involved in that appeal. On June 24, 2003, the court of appeals issued its ruling in the TVA case. It found unconstitutional the statutory scheme set forth in the Clean Air Act that allowed the EPA to impose penalties for failing to comply with an administrative compliance order, like the one issued to TVA, without the EPA having to prove the underlying violation. Thus, the court of appeals held that the compliance order was of no legal consequence, and TVA was free to ignore it. The court did not, however, rule directly on the substantive legal issues about the proper interpretation and application of certain NSR provisions that had been raised in the TVA appeal. On September 16, 2003, the court of appeals denied the EPA's request for a rehearing of the decision and on February 13, 2004, the EPA petitioned the U.S. Supreme Court to review the Eleventh Circuit's decision. At this time, no party to the Company's action, which was administratively closed two years ago, has asked the court to reopen that case.

Since the inception of the NSR proceedings against the Company, the EPA has also been proceeding with similar NSR enforcement actions against other utilities, involving many of the same legal issues. In each case, the EPA alleged that the utilities failed to comply with the NSR permitting requirements when performing maintenance and construction activities at coal-burning plants, which activities the Company considers to be routine or otherwise not subject to NSR. In 2003, district courts addressing these cases issued opinions that reached conflicting conclusions.

In October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act clarifying the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. On December 24, 2003, the U.S. Court of Appeals for the District of Columbia Circuit stayed the effectiveness of these revisions pending resolution of related litigation. In January 2004, the Bush Administration announced that it would continue to enforce the existing rules.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

On December 30, 2002, the Sierra Club, Physicians for Social Responsibility, Georgia ForestWatch, and one individual filed a civil suit in the U.S. District Court in Georgia against the Company for alleged violations of the Clean Air Act at four of the generating units at Plant Wansley. The complaint alleges Clean Air Act violations at both the existing coal-fired units and the new combined cycle units. Specifically, the plaintiffs allege (1) opacity violations at the coal-fired units, (2) violations of a permit provision that requires the combined cycle units to operate above certain levels, (3) violation of the nitrogen oxide emission offset requirements, and (4) violation of the hazardous air pollutant requirements. The civil action requests injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit.

On June 19, 2003, the court granted the Company motion to dismiss the allegations regarding hazardous air pollutants and denied the Company's motion to dismiss the allegations regarding emission offsets. On August 29, 2003, the Company filed a motion for partial summary judgment regarding emission offsets. On January 20, 2004, the Company filed a motion for summary judgment on the remaining three counts, and the plaintiffs have filed motions for partial summary judgment. The case is currently scheduled for trial during the summer of 2004. While the Company believes that it has complied with applicable laws and regulations, an adverse outcome could require payment of substantial penalties. The final outcome of this matter cannot now be determined.

Potentially Responsible Party Status

The Company has been designated as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation and Liability Act. The Company has recognized $34 million in cumulative expenses through December 31, 2003 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory. In addition, in 1995 the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. The Company has contributed to the removal and remedial investigation and feasibility study costs for the site. Additional claims for recovery of natural resource damages at the site are anticipated. As of December 31, 2003, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of the Company's activities relating to these sites, management does not believe that the Company's additional liability, if any, at these sites would be material to the financial statements.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three Georgia Power employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly, thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia. The lawsuit also raised claims on behalf of a purported class. The plaintiffs seek compensatory and punitive damages in an unspecified amount, as well as injunctive relief. In August 2000, the lawsuit was amended to add four more plaintiffs. Also, Southern Company Energy Solutions, a subsidiary of Southern Company, was named a defendant.

In October 2001, the district court denied the plaintiffs' motion for class certification. The plaintiffs filed a motion to reconsider the order denying class certification, and the court denied the plaintiffs' motion to reconsider. In December 2001, the plaintiffs filed a petition in the U. S. Court of Appeals for the Eleventh Circuit seeking permission to file an appeal of the October 2001 decision, and this petition was denied. After discovery was completed on the claims raised by the seven named plaintiffs, the defendants filed motions for summary judgment on all of the named plantiffs' claims. On March 31, 2003, the U.S. District Court for the Northern District of Georgia granted summary judgment in favor of the defendants on all claims raised by all seven plaintiffs. On April 23, 2003 plaintiffs filed an appeal to the U.S. Court of Appeals for the Eleventh Circuit challenging these adverse summary judgment rulings, as well as the District Court's October 2001 ruling denying class certification. Oral arguments occurred January 27, 2004, and the parties await the court's decision. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries including the Company, Gulf Power, Mississippi Power, and Southern Telecom (collectively defendants) have been named as defendants in numerous lawsuits brought by landowners since 2001 regarding the installation and use of fiber optic cable over defendants' rights of way located on the landowners' property. The plaintiffs' lawsuits claim that defendants may not use or sublease to third parties some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions by defendants exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment. The plaintiffs seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and the plaintiffs' claims are without merit. An adverse outcome in these matters could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric and Southern Telecom (collectively, defendants) were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against the telecommunications company in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

FERC Matters

The Company has obtained FERC approval to sell power to non-affiliates at market-based prices under specific contracts. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. In November 2001, the FERC modified the test it uses to consider utilities' applications to charge market-based rates and adopted a new test called the Supply Margin Assessment (SMA). The FERC applied the SMA to several utilities, including Southern Company's retail operating companies, and found them to be "pivotal suppliers" in their control area market and ordered the implementation of certain mitigation measures. SCS, on behalf of the Company and the other retail operating companies, sought rehearing of the FERC order and the FERC delayed implementation of certain mitigation measures. SCS, on behalf of the Company and the other retail operating companies, submitted comments to the FERC in 2002 regarding these issues. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. The Company anticipates that the FERC will address the requests for rehearing in the near future. Regardless of the outcome of the SMA proposal, the FERC retains the ability to modify or withdraw the authorization for any seller to sell at market-based rates, if it determines that the underlying conditions for having such authority are no longer applicable. The final outcome of this matter will depend on the form in which the SMA test and mitigation measures rules may be ultimately adopted and cannot be determined at this time.

PPAs by the Company for Southern Power's Plant McIntosh capacity were certified by the GPSC in December 2002 after a competitive bidding process. In April 2003, Southern Power applied for FERC approval of these PPAs. Interveners have made filings in opposition of the FERC's acceptance of the PPAs, alleging that the PPAs do not meet the applicable standards for market-based rates between affiliates. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held to determine: (a) whether, in the design and implementation of the GPSC competitive bidding process, the Company unduly preferred Southern Power; (b) whether the analysis of the competitive bids unduly favored Southern Power, particularly with respect to evaluation of non-price factors; (c) whether the Company selected its affiliate, Southern Power, based upon a reasonable combination of price and non-price factors; (d) whether Southern Power received an undue preference or competitive advantage in the competitive bidding process as a result of access to its affiliate's transmission system; (e) whether and to what extent the PPAs impact wholesale competition; and (f) whether the PPAs are just and reasonable and not unduly discriminatory. Hearings are scheduled to begin in March 2004. Management believes that the PPAs should be approved by the FERC; however, the ultimate outcome of this matter cannot now be determined.

4. JOINT OWNERSHIP AGREEMENTS

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 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. The term of the contract extends automatically for two-year periods, subject to either 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:

	2003	2002	2001
	(in millions)		
Energy	**$55**	$53	$52
Capacity	**34**	32	30
Total	**$89**	$85	$82

The Company owns undivided interests in plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company also jointly owns Plant McIntosh with Savannah Electric who operates the plant. The Company and Florida Power Corporation (FPC) jointly own a combustion turbine unit (Intercession City) operated by FPC.

At December 31, 2003, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,307	$1,706
Plant Hatch (nuclear)	50.1	908	469
Plant Wansley (coal)	53.5	390	160
Plant Scherer (coal)			
Units 1 and 2	8.4	115	52
Unit 3	75.0	560	247
Plant McIntosh			
Common Facilities (combustion-turbine)	75.0	24	3
Rocky Mountain (pumped storage)	25.4	169	85
Intercession City (combustion-turbine)	33.3	12	1

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners, except as noted above. The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the Statements of Income.

5. INCOME TAXES

Southern Company and its subsidiaries file a consolidated federal income tax return. As a result of new State of Georgia Department of Revenue regulations applicable to tax years beginning on or after January 1, 2002, Southern Company and its subsidiaries were granted permission by the State of Georgia Department of Revenue Commissioner to file a combined State of Georgia income tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. In accordance with both IRS and State of Georgia Department of Revenue regulations, each company is jointly and severally liable for the tax liability.

At December 31, 2003, tax-related regulatory assets were $510 million and tax-related regulatory liabilities were $187 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

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

	2003	2002	2001
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$143**	$261	$352
Deferred	**181**	60	(46)
	324	321	306
State:			
Current	**24**	31	61
Deferred	**16**	5	(8)
Deferred investment tax credits	**2**	-	5
Total	**$366**	$357	$364

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

	2003	2002
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,966**	$1,779
Property basis differences	**563**	623
Other	**329**	309
Total	**2,858**	2,711
Deferred tax assets:		
Federal effect of state deferred taxes	**96**	90
Other property basis differences	**156**	170
Other deferred costs	**160**	214
Other	**75**	64
Total	**487**	538
Net deferred tax liabilities	**2,371**	2,173
Portion included in prepaid expenses	**-**	3
Accumulated deferred income taxes in the Balance Sheets	**$2,371**	$2,176

In accordance with regulatory requirements, 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 $15 million in 2003, $12 million in 2002 and $15 million in 2001. At December 31, 2003, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2003	2002	2001
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	2	4
Non-deductible book depreciation	1	1	2
Other	(2)	(1)	(4)
Effective income tax rate	37%	37%	37%

6. CAPITALIZATION

Mandatorily Redeemable Preferred Securities

The Company has formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these preferred securities. At December 31, 2003, preferred securities of $940 million were outstanding and recognized as liabilities in the Balance Sheets.

Long-Term Debt Due Within One Year

A summary of the improvement fund requirements and scheduled maturities and redemptions of securities due within one year at December 31 is as follows:

	2003	2002
	(in millions)	
Capital lease	$2	$ 2
Senior notes	-	320
Total	$2	$322

Serial maturities through 2008 applicable to total long-term debt are as follows: $2 million in 2004; $453 million in 2005; $153 million in 2006; $303 million in 2007; and $3 million in 2008.

First Mortgage Bond Indenture

In 2002, the first mortgage bond indenture of the Company was defeased by paying to JPMorgan Chase Bank, the trustee, an amount representing the last outstanding obligations on the Company's first mortgage bonds. As a result of the defeasance, there are no longer any first mortgage bond liens on the Company's property and the Company no longer has to comply with the covenants and restrictions of the first mortgage bond indenture.

Pollution Control Bonds

The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2003 was $1.7 billion.

Capital Leases

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, 2003 and 2002, the Company had a capitalized lease obligation for its corporate headquarters building of $79 million and $81 million, respectively, with an interest rate of 8.1 percent. 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 has been deferred and is being amortized to expense as ordered by the GPSC. At both December 31, 2003 and 2002, the interest and lease amortization deferred on the Balance Sheets was $54 million.

Bank Credit Arrangements

At the beginning of 2004, the Company had an unused credit arrangement with banks totaling $725 million expiring at June 11, 2004. Upon expiration, the $725 million agreement provides the option of converting borrowings into a two-year term loan. The agreement contains stated borrowing rates but also allows for competitive bid loans. In addition, the agreement requires payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees are less than 1/8 of 1 percent for the Company.

Compensating balances are not legally restricted from withdrawal. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the agreement. Exceeding these limits would result in an event of default under the credit arrangement. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.

This $725 million in unused credit arrangements provides liquidity support to the Company's variable rate pollution control bonds. The amount of variable rate pollution control bonds outstanding requiring liquidity support as of December 31, 2003 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2003 was $137 million. There were no outstanding extendible commercial notes at December 31, 2003. The amount of commercial paper outstanding at December 31, 2002 was $358 million, which included $19 million of extendible commercial notes. During 2003, the peak amount of commercial paper outstanding was $531 million and the average amount outstanding was $229 million. The average annual interest rate on commercial paper in 2003 was 1.23 percent. Commercial paper is included in notes payable on the Balance Sheets.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs at the instruction of the GPSC. The Company also enters into hedges of forward electricity sales.

At December 31, 2003, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$3.2
Other comprehensive income	-
Net income	-
Total fair value	$3.2

The Company enters into derivatives to hedge exposure to interest rate changes. Derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives are generally structured to mirror the critical terms of the hedged debt instruments; therefore, no material ineffectiveness has been recorded in earnings.

At December 31, 2003, the Company had interest rate swaps outstanding with net deferred losses as follows:

Cash Flow Hedges

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value (Loss)
		(in millions)	
2004	1.39%	$873	$(0.8)
2005	1.56	50	0
2005	1.96	250	(1.1)

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2003, the Company recognized losses totaling $11.3 million upon termination of certain interest derivatives at the same time it issued debt. These losses have been deferred in other comprehensive income and will be amortized to interest expense over the life of the related debt. For 2003, approximately $3.4 million of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2004, pre-tax losses of approximately $3.2 million are expected to be reclassified from other comprehensive income to interest expense.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $747 million, $812 million, and $1,043 million in 2004, 2005, and 2006, respectively. These amounts include $28.9 million, $19.7 million and $20.0 million in 2004, 2005, and 2006, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel and Purchased Power Commitments." 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, changes in FERC rules and transmission regulations, revised load growth estimates, changes in environmental regulations, changes in existing nuclear plants to meet new regulatory requirements, increasing costs of labor, equipment, and materials, and cost of capital. At December 31, 2003, significant purchase commitments were outstanding in connection with the construction program.

The Company has no generating plants under construction. However, construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet the environmental standards previously discussed, are ongoing.

The Company had three generation projects under construction during 2001. They included two units at Plant Dahlberg, a ten-unit, 800 megawatt combustion turbine facility; two combined cycle units totaling 1,132 megawatts at Plant Wansley; and Plant Franklin, a two-unit, 1,181 megawatt combined cycle facility. All three of these projects have been transferred to Southern Power. The ten Dahlberg units and two Franklin units were transferred in 2001 and the transfer of the two Wansley units was completed in January 2002.

Southern Company has guaranteed Southern Power obligations totaling $10.7 million for the Company's construction of transmission interconnection facilities to these plants.

Fuel and Purchased Power 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. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile future prices at December 31, 2003. Also the Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2003 were as follows:

Year	Natural Gas	Coal and Nuclear Fuel
	(in millions)	
2004	$ 156	$1,321
2005	149	1,045
2006	148	895
2007	108	603
2008	172	372
2009 and thereafter	1,625	183
Total commitments	$2,358	$4,419

Additional commitments for coal and for nuclear fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company GAS. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company GAS is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail operating companies to insure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power or Southern Company GAS as a contracting party under these agreements.

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by MEAG that are in effect 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 $57 million, $57 million, and $59 million in 2003, 2002, and 2001, respectively. The current projected Plant Vogtle capacity payments are:

Year	Capacity Payments
	(in millions)
2004	$ 57
2005	56
2006	54
2007	54
2008	54
2009 and thereafter	369
Total	$644

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations at December 31, 2003 were as follows:

Year	Affiliated	Non-Affiliated
	(in millions)	
2004	$ 191	$ 45
2005	268	79
2006	283	88
2007	283	89
2008	282	90
2009 and thereafter	1,722	482
Total	$3,029	$873

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $36 million for 2003, $35 million for 2002, and $14 million for 2001. At December 31, 2003, estimated minimum rental commitments for these noncancelable operating leases were as follows:

	Minimum Obligations		
Year	Rail Cars	Other	Total
	(in millions)		
2004	$ 12	$22	$ 34
2005	12	18	30
2006	12	14	26
2007	10	12	22
2008	11	11	22
2009 and thereafter	56	16	72
Total	$113	$93	$206

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2004 and 2010, and the Company's maximum obligations are $13 million and $40 million, respectively. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation. A portion of the rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the GPSC.

Guarantees

Prior to 1999, a subsidiary of Southern Company originated loans to residential customers of the Company for heat pump purchases. These loans were sold to Fannie Mae with recourse for any loan with payments outstanding over 120 days. The Company is responsible for the repurchase of customers' delinquent loans. As of December 31, 2003, the outstanding loans guaranteed by the Company were $8.7 million and loan loss reserves of $1.8 million have been recorded.

Alabama Power has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligation corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty. In May 2003, SEGCO issued an additional $50 million in senior notes. Alabama Power guaranteed the debt obligation and in October 2003, the Company agreed to reimburse Alabama Power for the pro rata portion of such obligation corresponding to its then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

As discussed earlier in this note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

8. 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 provides funds up to $10.9 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), 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. The Company could be assessed up to $101 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, excluding any applicable state premium taxes -- based on its ownership and buyback interests -- is $203 million per incident but not more than an aggregate of $20 million to be paid for each incident in any one year. The Price-Anderson Amendments Act expired in August 2002; however, the indemnity provisions of the Act remain in place for commercial nuclear reactors.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

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 primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL subject to ownership limitations and has elected a 12 week waiting period.

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 current maximum annual assessments for the Company under the NEIL policies would be $40 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power stations would be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all "non-certified" terrorist acts (i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002 (TRIA). The NEIL aggregate -- applies to non-certified claims stemming from terrorism within a 12-month duration -- is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI cap is a $300 million shared industry aggregate. Any act of terrorism that is certified pursuant to the TRIA will not be subject to the foregoing NEIL and ANI limitations but will be subject to the TRIA annual aggregate limitation of $100 billion of insured losses arising from certified acts of terrorism. The TRIA will expire on December 31, 2005.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies 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.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2003 and 2002 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2003	**$1,126**	**$262**	**$133**
June 2003	**1,190**	**293**	**159**
September 2003	**1,487**	**490**	**265**
December 2003	**1,111**	**179**	**74**
March 2002	$1,007	$260	$127
June 2002	1,204	320	171
September 2002	1,517	498	271
December 2002	1,095	126	49

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 1999-2003
Georgia Power Company 2003 Annual Report

	2003	2002	2001	2000	1999
Operating Revenues (in thousands)	**$4,913,507**	$4,822,460	$4,965,794	$4,870,618	$4,456,675
Net Income after Dividends on Preferred Stock (in thousands)	**$630,577**	$617,629	$610,335	$559,420	$541,383
Cash Dividends on Common Stock (in thousands)	**$565,800**	$542,900	$527,300	$549,600	$543,000
Return on Average Common Equity (percent)	**14.05**	13.99	14.12	13.66	14.02
Total Assets (in thousands)	**$14,782,028**	$14,342,656	$14,447,973	$13,971,211	$13,148,049
Gross Property Additions (in thousands)	**$742,810**	$883,968	$1,389,751	$1,078,163	$790,464
Capitalization (in thousands):					
Common stock equity	**$4,540,211**	$4,434,447	$4,397,485	$4,249,544	$3,938,210
Preferred stock	**14,569**	14,569	14,569	14,569	14,952
Mandatorily redeemable preferred securities	**940,000**	940,000	789,250	789,250	789,250
Long-term debt	**3,762,333**	3,109,619	2,961,726	3,041,939	2,688,358
Total (excluding amounts due within one year)	**$9,257,113**	$8,498,635	$8,163,030	$8,095,302	$7,430,770
Capitalization Ratios (percent):					
Common stock equity	**49.0**	52.2	53.9	52.5	53.0
Preferred stock	**0.2**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**10.2**	11.1	9.6	9.7	10.6
Long-term debt	**40.6**	36.5	36.3	37.6	36.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**N/A**	N/A	A1	A1	A1
Standard and Poor's	**N/A**	N/A	A	A	A+
Fitch	**N/A**	N/A	AA-	AA-	AA-
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	a2	a2
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	A-
Fitch	**A**	A	A	A	A+
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,768,662**	1,734,430	1,698,407	1,669,566	1,632,450
Commercial	**258,276**	250,993	244,674	237,977	229,524
Industrial	**7,899**	8,240	8,046	8,533	8,958
Other	**3,434**	3,328	3,239	3,159	3,060
Total	**2,038,271**	1,996,991	1,954,366	1,919,235	1,873,992
Employees (year-end):	**8,714**	8,837	9,048	8,860	8,961

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 1999-2003 (continued)
Georgia Power Company 2003 Annual Report

	2003	2002	2001	2000	1999
Operating Revenues (in thousands):					
Residential	**$ 1,583,082**	$1,600,438	$ 1,507,031	$ 1,535,684	$ 1,410,099
Commercial	**1,661,054**	1,631,130	1,682,918	1,620,466	1,527,880
Industrial	**1,012,267**	1,004,288	1,106,420	1,154,789	1,143,001
Other	**53,569**	52,241	52,943	6,399	(30,892)
Total retail	**4,309,972**	4,288,097	4,349,312	4,317,338	4,050,088
Sales for resale - non-affiliates	**259,376**	270,678	366,085	297,643	210,104
Sales for resale - affiliates	**174,855**	98,323	99,411	96,150	76,426
Total revenues from sales of electricity	**4,744,203**	4,657,098	4,814,808	4,711,131	4,336,618
Other revenues	**169,304**	165,362	150,986	159,487	120,057
Total	**$4,913,507**	$4,822,460	$4,965,794	$4,870,618	$4,456,675
Kilowatt-Hour Sales (in thousands):					
Residential	**21,778,582**	22,144,559	20,119,080	20,693,481	19,404,709
Commercial	**26,940,572**	26,954,922	26,493,255	25,628,402	23,715,485
Industrial	**25,703,421**	25,739,785	25,349,477	27,543,265	27,300,355
Other	**595,742**	593,202	583,007	568,906	551,451
Total retail	**75,018,317**	75,432,468	72,544,819	74,434,054	70,972,000
Sales for resale - non-affiliates	**8,835,804**	8,069,375	8,110,096	6,463,723	5,060,931
Sales for resale - affiliates	**5,844,196**	3,962,559	3,133,485	2,435,106	1,795,243
Total	**89,698,317**	87,464,402	83,788,400	83,332,883	77,828,174
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.27**	7.23	7.49	7.42	7.27
Commercial	**6.17**	6.05	6.35	6.32	6.44
Industrial	**3.94**	3.90	4.36	4.19	4.19
Total retail	**5.75**	5.68	6.00	5.80	5.71
Sales for resale	**2.96**	3.07	4.14	4.43	4.18
Total sales	**5.29**	5.32	5.75	5.65	5.57
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,421**	12,867	11,933	12,520	12,006
Residential Average Annual Revenue Per Customer	**$902.70**	$929.90	$893.84	$929.11	$872.48
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**13,980**	14,059	14,474	15,114	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,153**	11,873	11,977	12,014	11,568
Summer	**14,826**	14,597	14,294	14,930	14,575
Annual Load Factor (percent)	**61.0**	60.4	61.7	61.6	58.9
Plant Availability (percent):					
Fossil-steam	**87.6**	80.9	88.5	86.1	84.3
Nuclear	**94.2**	88.8	94.4	91.5	89.3
Source of Energy Supply (percent):					
Coal	**58.6**	59.5	58.5	62.3	63.0
Nuclear	**16.8**	16.2	18.1	17.4	18.0
Hydro	**2.1**	0.9	1.1	0.7	0.9
Oil and gas	**0.3**	0.3	0.4	1.8	1.6
Purchased power -					
From non-affiliates	**7.5**	6.3	7.8	8.1	6.6
From affiliates	**14.7**	16.8	14.1	9.7	9.9
Total	**100.0**	100.0	100.0	100.0	100.0

Directors

Juanita P. Baranco
Chief Operating Officer
Baranco Automotive Group

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Anna R. Cablik
Owner and President
Anatek, Inc. & Anasteel & Supply Co., LLC

H. Allen Franklin
Chairman, President and Chief Executive Officer
Southern Company

Michael D. Garrett
President
Georgia Power Company

David M. Ratcliffe
Chairman of the Board and Chief Executive Officer
Georgia Power Company

D. Gary Thompson
Chief Executive Officer
Georgia Banking Wachovia Corporation

Richard W. Ussery
Chairman of the Board
TSYS

William Jerry Vereen
Chairman, President and Chief Executive Officer
Riverside Manufacturing Company

Carl Ware
Executive Vice President
The Coca-Cola Company

E. Jenner Wood, III
Chairman, President and Chief Executive Officer
SunTrust Bank, Central Group

Officers

David M. Ratcliffe
Chairman of the Board and Chief
Executive Officer

Michael D. Garrett
President

Judy M. Anderson
Senior Vice President
Charitable Giving

William C. Archer, III
Executive Vice President
External Affairs

Ronnie L. Bates
Senior Vice President
Planning, Sales and Service

M. A. Brown
Senior Vice President
Distribution

C. B. (Mike) Harreld
Executive Vice President, Treasurer and Chief
Financial Officer

Richard L. Holmes
Senior Vice President
Corporate Services

James H. Miller, III *(effective 3/13/04)*
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Chris C. Womack
Senior Vice President
Fossil and Hydro Power

W. Craig Barrs
Vice President
Community and Economic Development

Rebecca A. Blalock
Vice President
Information Resources

A. Bryan Fletcher
Vice President
Region Distribution

J. Kevin Fletcher
Vice President
Marketing and Customer Service

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer

Chris M. Hobson
Vice President
Environmental Affairs

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

E. Lamont Houston
Vice President
Region Distribution

Brian L. (Pete) Ivey
Vice President
Administrative Services

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President
Human Resources

Frank J. McCloskey
Vice President
Diversity and Corporate Relations

James E. Sykes, Jr.
Vice President
Region Distribution

J. L. Wallace
Vice President
Planning and Pricing

Janice G. Wolfe
Corporate Secretary and
Assistant Comptroller

Wayne Boston
Assistant Secretary and
Assistant Treasurer

General
This annual report is submitted for general information and is not intended for use in connection with any sale or purchase of, or any solicitation of offers to buy or sell, securities.

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Georgia. The Company sells electricity to some 2.0 million customers within its service area of approximately 57,000 square miles. In 2003, retail energy sales accounted for 84 percent of the Company's total sales of 89.7 billion kilowatt-hours.

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five regulated Southeast utilities. There is no established public trading market for the Company's common stock.

Audit Committee
In 2003, the board of directors amended the Company's bylaws to remove the provision requiring an Audit Committee and to create a Controls and Compliance Committee. The Southern Company Audit Committee provides broad oversight of the Company's financial reporting and control functions.

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes and Preferred Securities
JPMorgan Chase Bank
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Registrar, Transfer Agent, and Dividend Paying Agent
Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (404) 506-7450.

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