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2004 Annual Report

Georgia Power Company

GEORGIA POWER Co.

A SOUTHERN COMPANY

CONTENTS

Georgia Power Company 2004 Annual Report

SUMMARY

	2004	2003	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$5,371**	$4,914	9.3
Operating expenses	**$4,112**	$3,690	11.4
Net income after dividends on preferred stock	**$658**	$631	4.3
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**77,904**	75,018	3.8
Sales for resale - non-affiliates	**5,970**	8,836	(32.5)
Sales for resale - affiliates	**4,783**	5,844	(18.2)
Total	**88,657**	89,698	(1.2)
Customers served at year-end *(in thousands)*	**2,078**	2,038	2.0
Peak-hour demand *(in megawatts)*	**15,180**	14,826	2.4
Capitalization Ratios *(percent):*			
Common stock equity	**51.0**	49.0	
Preferred stock	**0.2**	0.2	
Mandatorily redeemable preferred securities	-	10.2	
Long-term debt payable to affiliated trusts	**10.1**	-	
Long-term debt	**38.7**	40.6	
Return on Average Common Equity *(percent)*	**13.95**	14.05	
Ratio of Earnings to Fixed Charges *(times)*	**5.11**	5.01	

LETTER TO INVESTORS
Georgia Power 2004 Annual Report

Looking back, 2004 will likely be remembered as the year of the hurricanes. Georgia Power employees, along with others across our Southern Company system, battled an unprecedented four hurricanes in six weeks to restore power throughout the Southeast.

Georgia Power not only achieved high marks in restoration and reliability, but we also demonstrated once again that we can take care of our customers' needs, improve efficiency, support our communities and meet the growing demand for energy in this vibrant state.

Strong operational excellence, combined with exceptional financial performance in 2004, resulted in an outstanding year for the company.

Georgia Power's 2004 earnings totaled $658 million, a $27 million, or 4.3 percent increase, from 2003. We earned a 13.95 percent total company return on average common equity during 2004. Georgia Power had a net plant in service investment of $11.5 billion at the end of the year, with total assets of $15.8 billion. Operating revenues for 2004 were $5.4 billion.

Our solid results for 2004 were achieved, despite the extensive damage and economic disruption caused by Hurricanes Charley, Frances, Ivan and Jeanne in August and September.

Ivan was the worst storm in Southern Company's history, knocking out power to hundreds of thousands of Georgia Power customers. Because of the outstanding response by Georgia Power employees and our sister companies, with assistance from many other companies and organizations, we restored service to our customers in record time.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals continued to be drawn to the state, increasing the number of customers Georgia Power serves to approximately 2.1 million in 2004, a 2 percent increase from the previous year.

Our retail sales of electricity climbed 3.8 percent in 2004 as we maintained an excellent reliability record. In fact, Georgia Power plants achieved a superior peak season equivalent forced outage rate of 0.81 percent, surpassing our peak goal of 2.9 percent.

As demand for electricity increases, we continue to provide options for our customers to help manage their consumption of electricity.

Nearly 20,000 customers now participate in the Power Credit program, an electricity demand-saving service designed to efficiently control the amount of electricity a residential customer's air conditioner uses during peak demand periods in the summer months. The program helps Georgia Power meet demand and lower its overall cost to serve customers during peak periods.

Improving efficiency across the company is one of our main goals. In 2004, we replaced 92-year-old turbines at Plant Goat Rock with more efficient models that will require less maintenance and generate more power. The turbines also have a more "fish friendly" design.

Our environmental efforts are just one way we demonstrate our commitment to being a Citizen Wherever We Serve. Through our economic development activities, Georgia Power was instrumental in locating 65 new or expanding businesses in the state, which will bring a record $1.5 billion in new capital investment and 8,678 new jobs to our state.

To meet growing customer demand for electricity, the Georgia Public Service Commission approved a rate increase for Georgia Power late last year that will mean a 4.2 percent, or about $3.10 a month, change in the average residential customer's bill, beginning in 2005.

This is the company's first base rate increase in 13 years – even though we're serving 486,000 more customers. The rate increase will recover higher operations and investment costs, including power lines, new generation sources, environmental controls and other necessary infrastructure to meet demand.

Increasing supplier diversity is a key goal for our company. Last year, we spent $157.6 million, or 13.5 percent of our total procurement dollars, excluding fuel, with minority- and female-owned businesses. We surpassed our goal of 11.25 percent and have set a goal of 12.35 percent for 2005.

Without a doubt, our employees delivered another outstanding performance in 2004 by continuing to focus on the fundamentals of providing customers with reliable, cost-effective power and great service. We will continue that success in 2005 as we work to meet our state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 18, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2004 and 2003, 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, 2004. 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.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 25 to 55) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, 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
February 28, 2005

OVERVIEW

Business Activities

Georgia Power Company (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.

Many factors affect the opportunities, challenges and risks 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 stringent environmental standards. In 2004, the Company completed a major retail rate proceeding that should help provide future earnings stability. This regulatory action will also enable the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continue environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

The Company strives to maximize shareholder value while providing low-cost energy to more than 2 million customers by focusing on several key indicators. These include customer satisfaction, peak season equivalent forced outage rate (Peak Season EFOR), and return on equity (ROE). The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring that satisfaction include outstanding service, high reliability, and competitive prices. Management uses nationally recognized customer satisfaction surveys and reliability indicators to evaluate the Company's results. Peak Season EFOR is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. ROE is a performance standard used by the investment community and many regulatory agencies.

The Company's 2004 results compared to its targets for each of these indicators are reflected in the following chart.

Key Performance Indicator	2004 Target Performance	2004 Actual Performance
Customer Satisfaction	Top quartile performance on national surveys	**Top quartile**
Peak Season EFOR	2.90% or less	**0.81%**
ROE	13.70%	**13.95%**

The strong financial performance achieved in 2004 reflects the focus that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense in the final year of a Georgia Public Service Commission (PSC) retail rate plan that was effective January 2002 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The 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 resulting from lower financing costs and a lower effective tax rate due to the realization of certain state tax credits. 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 the 2001 Retail Rate Plan.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2004	**2004**	2003	2002
		(in millions)		
Operating revenues	**$5,371**	**$457**	$ 92	$(144)
Fuel	**1,233**	**128**	101	64
Purchased power	**976**	**200**	92	(87)
Other operation and maintenance	**1,400**	**153**	(78)	85
Depreciation and amortization	**275**	**(74)**	(54)	(197)
Taxes other than income taxes	**228**	**15**	11	(1)
Total operating expenses	**4,112**	**422**	72	(136)
Operating income	**1,259**	**35**	20	(8)
Total other income and (expense)	**(221)**	**5**	2	9
Income taxes	**379**	**13**	9	(7)
Net income	**659**	**27**	13	8
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 658**	**$ 27**	$ 13	$ 8

Revenues

Operating revenues in 2004, 2003, and 2002 and the percent of change from the prior year are as follows:

	Amount		
	2004	2003	2002
		(in millions)	
Retail – prior year	**$4,310**	$4,288	$4,349
Change in -			
Base rates	**-**	-	(118)
Sales growth and other	**151**	30	2
Weather	**32**	(66)	82
Fuel cost recovery and other	**284**	58	(27)
Retail – current year	**4,777**	4,310	4,288
Sales for resale -			
Non-affiliates	**247**	260	271
Affiliates	**166**	175	98
Total sales for resale	**413**	435	369
Other operating revenues	**181**	169	165
Total operating revenues	**$5,371**	$4,914	$4,822
Percent change	**9.3%**	1.9%	(2.9)%

Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 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. 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 2001 Retail Rate Plan and generally lower prices to large business customers.

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. In August 2003, the Georgia PSC issued an order allowing the Company to increase customer fuel rates to recover existing under recovered deferred fuel costs. In recent months, the Company has experienced higher than expected fuel costs for coal and gas. Those higher fuel costs have increased the under recovered fuel costs. On February 18, 2005, the Company filed a request with the Georgia PSC for a fuel cost recovery rate increase. In the ordinary course, these new rates will be effective June 1, 2005 following a hearing before and approval by the Georgia PSC. In its filing, the Company asked that the Georgia PSC accept the new rate, effective April 1, 2005, prior to a formal hearing on the Company's request. This action, if taken by the Georgia PSC, would serve to mitigate expected increases in the under recovered balance during April and May, but will not preclude the Georgia PSC from subsequently adjusting the rates. The requested increase, representing an annual increase in revenues of approximately 11.7 percent, will allow for the recovery of fuel costs based on an estimate of future fuel costs, as well as the collection of the existing under recovery of fuel costs. The Company's under recovered fuel costs as of January 31, 2005 totaled $390 million. The Georgia PSC will examine the Company's fuel expenditures and determine whether the proposed fuel cost recovery rate is just and reasonable before issuing its decision in May 2005. The final outcome of the filing cannot be determined at this time. See Note 3 to the financial statements under "Fuel Cost Recovery" for further information regarding this filing.

Wholesale revenues from sales to non-affiliated utilities were:

	2004	2003	2002
		(in millions)	
Unit power sales --			
Capacity	**$ 31**	$ 34	$ 34
Energy	**33**	31	34
Other power sales --			
Capacity	**75**	93	62
Energy	**108**	102	141
Total	**$247**	$260	$271

Revenues from unit power sales contracts remained relatively constant in 2004. Revenues from unit power contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales decreased $12 million (6.2 percent), $8 million (3.9 percent), and $102 million (33.4 percent) in 2004, 2003, and 2002, respectively, 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. These affiliated sales and purchases are made in accordance with the affiliate company interchange agreement, as approved by the Federal Energy Regulatory Commission (FERC). In 2004, kilowatt-hour (KWH) energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH 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 $11.7 million (6.9 percent) in 2004 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. 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 revenues from the rental of electric property of $4 million. Other operating revenues in 2002 increased $14 million (9.5 percent) primarily due to the collection of new late payment fees approved under the 2001 Retail Rate Plan 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.

Energy Sales

KWH sales for 2004 and the percent change by year were as follows:

	KWH	Percent Change		
	2004	**2004**	2003	2002
	(in billions)			
Residential	**22.9**	**5.3%**	(1.7)%	10.1%
Commercial	**28.0**	**4.0**	(0.1)	1.7
Industrial	**26.4**	**2.5**	(0.1)	1.5
Other	**0.6**	**1.1**	0.4	1.7
Total retail	**77.9**	**3.8**	(0.5)	4.0
Sales for resale -				
Non-affiliates	**6.0**	**(32.5)**	9.5	(0.5)
Affiliates	**4.8**	**(18.2)**	47.5	26.5
Total sales for resale	**10.8**	**(26.8)**	22.0	7.0
Total sales	**88.7**	**(1.2)**	2.6	4.4

Residential KWH sales increased 5.3 percent in 2004 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy. Residential KWH sales decreased 1.7 percent in 2003 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 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 in 2002 increased 1.7 percent and 1.5 percent, respectively, due to corresponding increases of 2.6 percent and 2.4 percent, respectively, in customers. Retail sales growth assuming normal weather is expected to be 1.9 percent on average from 2005 to 2009.

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, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2004	2003	2002
Total generation (billions of KWH)	**71.5**	73.1	70.4
Sources of generation (percent) --			
Coal	**75.4**	75.4	77.4
Nuclear	**22.5**	21.6	21.1
Hydro	**2.0**	2.7	1.2
Oil and gas	**0.1**	0.3	0.3
Average cost of fuel per net KWH generated (cents) --	**1.55**	1.46	1.42
Average cost of purchased power per net KWH (cents) --	**5.17**	4.03	3.29

Fuel expense increased 11.6 percent in 2004 primarily due to an increase in the average cost of fuel. 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.

Purchased power expense increased $200 million (25.9 percent) in 2004 primarily due to a 38.5 percent increase in the average cost of fuel per net KWH and $65 million of additional capacity expense associated with new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in June 2004 and June 2003. Purchased power expense increased $92 million (13.3 percent) in 2003 primarily due to $75 million of additional capacity expense associated with new PPAs between the Company and Southern Power that went into effect in 2003 and 2002. Purchased power expense decreased $87 million (11.2 percent) in 2002 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 PPAs between the Company and Southern Power.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2004 hurricanes, result in an immediate market response; however, the impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

In 2004, other operation and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. 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.

Depreciation and amortization decreased $74 million and $54 million in 2004 and 2003, respectively, primarily as a result of the amortization of a regulatory liability related to the inclusion of new certified PPAs in retail rates on a levelized basis as ordered by the Georgia PSC. 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 as part of the 2001 Retail Rate Plan. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. 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.

Allowance for equity funds used during construction increased $15.9 million in 2004 primarily due to the Company's acquisition of the Plant McIntosh combined cycle Units 10 and 11 construction project from Southern Power. See FUTURE EARNINGS POTENIAL – "FERC and Georgia PSC Matters" and Note 3 to the financial statements under "Retail Rate Orders" and "Plant McIntosh Construction Project" for additional information.

Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003. Interest income remained relatively constant in 2002.

Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. Interest expense decreased in 2002 primarily due to lower interest rates that offset new financing costs. The Company refinanced or retired $400 million, $665 million, and $929 million of securities in 2004, 2003, and 2002, respectively. Interest capitalized increased in 2004 due to the Plant McIntosh construction project referenced above and decreased in 2003 and 2002 due to the transfer of three generation projects to Southern Power in 2002 and 2001. See Note 3 to the financial statements under "Retail Rate Orders" and "Plant McIntosh Construction Project" for additional information regarding the Plant McIntosh construction project.

Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs pursuant to a Georgia PSC order issued on December 21, 2004 (2004 Retail Rate Plan), partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Rate Orders" and "Plant McIntosh Construction Project" for additional information on the disallowance.

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, preferred stock, 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 Company operates as a vertically integrated company providing electricity to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the southeastern United States. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for electricity relating to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and revenues are reviewed and adjusted periodically within certain limitations based on earned ROE. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Rate Orders" and "Market-Based Rate Authority" for additional information about this and other regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to recover costs related to growing demand, to achieve energy sales growth while containing costs, and to meet increasingly stringent environmental standards. Future earnings 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.

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 adverse financial impact regarding its limited energy trading operations through Southern Company Services, Inc. (SCS).

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company, alleging that the Company had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to coal-fired generating facilities at plants Bowen and Scherer. 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 was effectively stayed in the spring of 2001 pending the appeal of a similar NSR action against the Tennessee Valley Authority (TVA) before the U.S. Court of Appeals for the Eleventh Circuit. In June 2003, the Court of Appeals issued its ruling in the TVA case, dismissing the appeal for reasons unrelated to the issues in the case pending against the Company. At this time, no party to the case against the Company has sought to reopen the case, which remains administratively closed in the U.S.

District Court for the Northern District of Georgia. See Note 3 to the financial statements under "New Source Review Actions" for additional information.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. 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 possibly financial condition if such costs are not recovered through regulated rates.

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 (RMRR) exclusion. A coalition of states and environmental organizations has filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. The October 2003 RMRR rules have been stayed by the Court of Appeals pending its review of the rules. In any event, the final regulations must also be adopted by the State of Georgia in order to apply to the Company's facilities. The effect of these final regulations, related legal challenges, and potential rulemakings by the State of Georgia cannot be determined at this time.

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 for the Northern District of 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. The liability phase of the case has concluded with the Court ruling in favor of the Company in part and the plaintiffs in part. The Company has filed a petition for review of the decision with the U.S. Court of Appeals for the Eleventh Circuit. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate remedy trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. See Note 3 to the financial statements under "Plant Wansley Environmental Litigation" for additional information. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could result in 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 possibly financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

On July 21, 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel of New York filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining, global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. Southern Company and the other defendants have filed motions to dismiss both lawsuits. Southern Company intends to vigorously defend against these claims. While the outcome of these matters cannot be determined at this time, an adverse judgment could result in substantial capital expenditures.

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 involves 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 FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the 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 and resulted in total construction expenditures of approximately $206 million through 2000. Some of these previous 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 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 totaled $687.2 million through 2004, with an additional $6 million committed through 2007.

To help 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 could be applied in Georgia. In April 2004, the EPA published final regional nitrogen oxide reduction rules applicable to Georgia, specifying a May 1, 2007 compliance date. However, in October 2004, the EPA announced that it would stay implementation of the rule as it relates to Georgia, while it initiates rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the nitrogen oxide reduction rules will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of Georgia's state implementation plan and cannot be determined at this time.

In September 2003, the EPA reclassified the Atlanta area from a "serious" to a "severe" nonattainment area for the one-hour ozone standard effective January 1, 2004. However, based on the last three years of data, the State of Georgia believes that the Atlanta area has attained the one-hour standard and is in the process of applying for redesignation from the EPA.

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 and included development of an eight-hour ozone standard, as opposed to the previous one-hour ozone standard. 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. On April 30, 2004, the EPA published its eight-hour ozone nonattainment designations and a portion of the rules implementing the new eight-hour standard. Areas within the Company's service territory that have been designated as nonattainment under the eight-hour ozone standard include Macon, Georgia and a 20-county area within metropolitan Atlanta. Under the implementation provisions of the new rule, the EPA announced that the one-hour ozone standard will be revoked on June 15, 2005, and that areas classified as "severe" nonattainment areas under the one-hour standard, such as Atlanta, will not be required to impose emissions fees if those areas fail to come into attainment with the one-hour standard. With respect to the eight-hour nonattainment areas, state implementation plans, including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. These state implementation plans could require reductions in nitrogen oxide emissions from power plants. The impact of the eight-hour designations and the new standard will depend on the development and implementation of applicable state implementation plans and therefore cannot be determined at this time.

On December 17, 2004, the EPA issued its final "nonattainment" designations for the fine particulate national ambient air quality standard. Several areas within the Company's service territory in Georgia were included in the EPA's final particulate matter designations. The EPA plans to propose a fine particulate matter implementation rule in 2005 and finalize the implementation rule in 2006. State implementation plans addressing the nonattainment designations may be required by 2008 and could require reductions in sulfur dioxide emissions and further reductions in nitrogen oxide emissions from power plants. The impact of the fine particulate designations will depend on the development and implementation of applicable state implementation plans and therefore cannot be determined at this time.

In January 2004, the EPA issued a proposed Clean Air Interstate Rule (CAIR) 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 in 2005. If finalized, the rule could modify or supplant other state requirements for attainment of the fine particulate matter standard, the eight-hour ozone standard, and other air quality regulations. 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.

The Company has developed and maintains an environmental compliance strategy for the installation of additional control technologies and the purchase of emission allowances to assure continued compliance with current sulfur dioxide and nitrogen oxide emission regulations. Additional expenses associated with these regulations are anticipated to be incurred each year to maintain current and future compliance. Because the Company's compliance strategy is impacted by factors such as changes to existing environmental laws and regulations, increases in the cost of emissions allowances, and any changes in the Company's fuel mix, future environmental compliance costs 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 and to implement emission reduction requirements that make progress toward remedying current visibility impairment in certain natural areas. 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 implementation plans in 2008 that contain emission reduction strategies for implementing BART and for achieving sufficient progress toward the Clean Air Act's visibility improvement goal. In response to litigation, the EPA proposed revised rules in May 2004, which it plans to finalize in April 2005. The impact of these regulations will depend on the promulgation of final rules and implementation of those rules by the states and, therefore, it is not possible to determine the effect of these rules on the Company at this time.

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 March 2005, and compliance could be required as early as 2008. Because the regulations have not been finalized, the impact on the Company cannot be determined at this time.

Major bills to amend the Clean Air Act to impose more stringent emissions limitations on power plants, including the Bush Administration's Clear Skies Act, have been proposed in 2005. The Clear Skies Act is expected to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury and to supplement the proposed CAIR and mercury regulatory programs. Other proposals have also been introduced 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.

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. In July 2004, the EPA published final rules that will require 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 and the actual limits established by the regulatory agencies.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 with two others scheduled for completion in 2008. The total estimated cost of these projects is $248 million, with $170 million remaining to be spent. Also, the Company is conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

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 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.

Global Climate Issues

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 constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and, in 2002, announced a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is leading the development of a voluntary electric utility sector climate change initiative in partnership with the government. The utility sector has pledged to reduce its greenhouse gas emissions rate by 3 to 5 percent over the next decade and, on December 13, 2004, signed a memorandum of understanding with the DOE initiating this program under Climate VISION. Because efforts under this voluntary program are just beginning, the impact of this program on the Company cannot be determined at this time.

Environmental Remediation Reserves

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 for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs of the Company. Under the 2004 Retail Rate Plan, this regulatory liability will be amortized as a credit to expense over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures will be charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

FERC and Georgia PSC Matters

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to nonaffiliates at market-based prices. 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, the retail operating companies, and Southern Power, and found Southern Company, and others to be "pivotal suppliers" in their retail service territories and ordered the implementation of several mitigation measures. Southern Company and others sought rehearing of the FERC order, and the FERC delayed the implementation of certain mitigation measures. In April 2004, the FERC issued an order that abandoned the SMA test and adopted a new interim analysis for measuring generation market power. This new interim approach requires utilities to submit a pivotal supplier screen and a wholesale market share screen. If the applicant does not pass both screens, there will be a rebuttable presumption regarding generation market power. The FERC's order also sets forth procedures for rebutting these presumptions and addresses mitigation measures for those entities that are found to have market power. In the absence of specific mitigation measures, the order includes several cost-based mitigation measures that would apply by default. The FERC also initiated a new rulemaking proceeding that, among other things, will adopt a final methodology for assessing generation market power.

In July 2004, the FERC denied Southern Company's request for rehearing, along with a number of others, and reaffirmed the interim tests that it adopted in April 2004. In August 2004, Southern Company submitted a filing to the FERC which included results showing that Southern Company passed the pivotal supplier screen for all markets and the wholesale market share screen for all markets except the Southern Company retail service territory. Southern Company also submitted other analyses to demonstrate that it lacks generation market power. On December 17, 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not at issue. As directed by this order, on February 15, 2005, Southern Company submitted additional information related to generation dominance in its retail service territory. Any new market-based rate transactions in the Southern Company retail service territory entered into after February 27, 2005 will be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Southern Company, along with other utilities, has also filed an appeal of the FERC's April and July 2004 orders with the U.S. Court of Appeals for the District of Columbia Circuit. The FERC has asked the court to dismiss the appeal on the grounds that it is premature.

In the event that the FERC's default mitigation measures are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

Retail Rate Case

On December 21, 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings will be evaluated annually against a retail ROE range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates will be increased by approximately $194 million and customer fees will be increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability.

The Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified or discontinued. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric and Power Company (Savannah Electric) for capacity from Plant McIntosh Units 10 and 11, construction of which is scheduled to be completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. The ultimate outcome of any additional FERC action cannot now be determined at this time.

As directed by the Georgia PSC order, in June 2004, the Company and Savannah Electric filed an application to amend the resource certificate granted by the Georgia PSC in 2002 to change the character of the resource from a PPA to a self-owned, rate based asset and to describe the approximate construction schedule and the proposed rate base treatment. In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflects an approximate $16 million disallowance, of which $13 million is attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. The amount of the disallowance will be adjusted accordingly based on the actual completion cost of the project. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Rate Orders" and "Plant McIntosh Construction Project" for additional information.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein. On February 18, 2005, the Company filed a request with the Georgia PSC for a fuel cost recovery rate increase. In the ordinary course, these new rates will be effective June 1, 2005 following a hearing before and approval by the Georgia PSC. In its filing, the Company asked that the Georgia PSC accept the new rate, effective April 1, 2005, prior to a formal hearing on the Company's request. This action, if taken by the Georgia PSC, would serve to mitigate expected increases in the under recovered balance during April and May, but will not preclude the Georgia PSC from subsequently adjusting the rates. The requested increase, representing an annual increase in revenues of approximately 11.7 percent, will allow for the recovery of fuel costs based on an estimate of future fuel costs, as well as the collection of the existing under recovery of fuel costs. The Company's under recovered fuel costs as of January 31, 2005 totaled $390 million. The Georgia PSC will examine the Company's fuel expenditures and determine whether the proposed fuel cost recovery rate is just and reasonable before issuing its decision in May 2005. The final outcome of the filing cannot be determined at this time. See Note 3 to the financial statements under "Fuel Cost Recovery" for further information regarding this filing.

Storm Damage Cost Recovery

During the month of September 2004, the Company's service territory was impacted by Hurricanes Frances, Ivan and Jeanne. The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The total amount of damage related to these hurricanes was estimated to be approximately $15 million and was charged to the storm damage reserve in 2004. These costs are expected to be recovered through regular monthly accruals which total $6.3 million annually under the 2004 Retail Rate Plan. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Other Matters

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 $35 million, $54 million, and $59 million in 2004, 2003, and 2002, respectively. Future pension income is dependent on several factors including trust earnings and changes to the pension 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 $44 million, $41 million and $43 million in 2004, 2003, and 2002, respectively, and are expected to trend upward. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

On October 22, 2004, President Bush signed the American Jobs Creation Act of 2004 (Jobs Act) into law. The Jobs Act includes a provision that allows a generation tax deduction for utilities. The Company is currently assessing the impact of the Jobs Act, including this deduction, as well as the related regulatory treatment, on its taxable income. However, the Company currently does not expect the Jobs Act to have a material impact on its financial statements.

The Company is involved in various other 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. Southern Company senior management has discussed the development and selection of the critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC 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, which requires the financial statements to reflect the effects of rate 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, 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 legislative, 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 herein 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, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume and other power delivery operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

On March 31, 2004, the Company prospectively adopted FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities," which requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. The adoption of FASB Interpretation No. 46R had no impact on the Company's net income. However, as a result of the adoption, the Company deconsolidated certain wholly-owned trusts established to issue preferred securities since the Company did not meet the definition of primary beneficiary established by FASB Interpretation No. 46R. See Note 1 to the financial statements under "Variable Interest Entities" for additional information.

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 by approximately $5 million and is expected to have a similar impact on future expenses. The subsidy's impact on the postretirement medical plan APBO was a reduction of approximately $72 million. However, the ultimate impact on future periods is subject to final interpretation of the federal regulations which were published on January 21, 2005. See Note 2 to the financial statements under "Postretirement Benefits" for additional information.

FASB Statement No. 123R, Share-Based Payments, was issued in December 2004. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. For the Company, this statement is effective beginning July 1, 2005. Although the compensation expense calculation required under the revised statement differs slightly, the impacts on the financial statements are expected to be similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for information regarding the adoption of new tax legislation. In December 2004, the FASB issued FSP 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities provided by the American Jobs Creation Act of 2004, which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company is currently assessing the Jobs Act and this pronouncement, as well as the related regulatory treatment, but currently does not expect a material impact on the Company's financial statements.

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 costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations decreased $219 million resulting primarily from the increase in under recovered deferred fuel costs.

In 2004, gross utility plant additions were $1.1 billion. These additions were primarily related to the construction of Plant McIntosh Units 10 and 11, 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 and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 47.7 percent in 2004 and 48.3 percent in 2003 and 2002. 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 capital contributions from

Southern Company and by the issuance of new debt securities, term loans, and short-term borrowings. 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 securities to meet its long-term external financing requirements.

The issuance of securities by the Company is subject to regulatory approval by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935, as amended (PUHCA), and by the Georgia PSC. Additionally, with respect to the public offering of securities, the Company must file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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 PUHCA, most loans between affiliated companies must be approved in advance by the 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 $773.1 million of unused credit arrangements with banks at the beginning of 2005. 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. As of December 31, 2004, the Company had outstanding $208 million of commercial paper and no extendible commercial notes.

At the beginning of 2005, the Company had not used any of its available credit arrangements. Bank credit arrangements are as follows:

		Expires		
Total	Unused	2005	2006	2007
		(in millions)		
$773.1	$773.1	$423.1	-	$350

The credit arrangements that expire in 2005 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2004, the Company issued $806 million of long-term debt including long-term debt payable to affiliated trusts. The issuances were used to refund $400 million of long-term debt, as well as to finance the Company's purchase of the Plant McIntosh construction project from Southern Power. The remainder was used to reduce short-term debt and fund the Company's ongoing construction program.

Subsequent to December 31, 2004, the Company has issued $250 million of securities with the proceeds used to fund the February 2005 maturity of floating rate senior notes.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2004, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $8 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $247 million. The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price and interest rate risk management activities. At December 31, 2004, the Company had no material exposure related to these 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 exposure to interest rates, the Company has entered into interest rate swaps that have been designated as hedges. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2005 was 2.04 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $8 million at January 1, 2005. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

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.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2004	2003
	(in millions)	
Contracts beginning of year	**$3.2**	$ 0.1
Contracts realized or settled	**(12.2)**	(0.4)
New contracts at inception	-	-
Changes in valuation techniques	-	-
Current period changes (a)	**14.8**	3.5
Contracts end of year	**$5.8**	$ 3.2

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

	Source of 2004 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in millions)		
Actively quoted	**$4.8**	$3.8	$1.0
External sources	**1.0**	1.0	-
Models and other methods	-	-	-
Contracts end of year	**$5.8**	$4.8	$1.0

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. See Note 3 to the financial statements for information regarding the retail fuel hedging program. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2004, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$5.7
Other comprehensive income	-
Net income	0.1
Total fair value	$5.8

Unrealized gains (losses) recognized in income in 2004, 2003, and 2002 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 $911 million for 2005, $1.1 billion for 2006, and $1.2 billion for 2007. Environmental expenditures included in these amounts are $127 million, $284 million, and $506 million for 2005, 2006, and 2007, 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 currently has under construction Plant McIntosh Units 10 and 11 scheduled for completion in June 2005. In addition, 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 Nuclear Regulatory Commission, 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 "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 Georgia PSC and the FERC.

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

Contractual Obligations

	2005	2006-2007	2008-2009	After 2009	Total
			(in millions)		
Long-term debt [a] --					
Principal	$ 452	$ 456	$ 282	$ 3,942	$ 5,132
Interest	232	426	387	4,283	5,328
Preferred stock dividends[b]	1	1	1	-	3
Operating leases	32	52	42	63	189
Purchase commitments[c] --					
Capital [d]	911	2,277	2,571	-	5,759
Coal and nuclear fuel	1,731	2,722	771	96	5,320
Natural gas[e]	248	388	389	1,669	2,694
Purchased power	339	692	673	1,222	2,926
Long-term service agreements	6	19	22	150	197
Trusts[f] --					
Nuclear decommissioning	9	14	14	124	161
Postretirement benefits	8	24	-	-	32
DOE assessments	3	4	-	-	7
Total	$3,972	$7,075	$5,152	$11,549	$27,748

(a) All amounts are reflected based on final maturity dates. The Company plans to 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, 2005, 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 $1.4 billion, $1.2 billion, and $1.3 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, 2004, 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 Exchange future prices at December 31, 2004.
(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. 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, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2004 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, completion of construction projects, and estimated construction and other expenditures. 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 similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- 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 the impact of pending and future rate cases and negotiations;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, 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 effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and 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;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company (including the Form 10-K) from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003, and 2002

Georgia Power Company 2004 Annual Report

	2004	2003	2002
		(in thousands)	
Operating Revenues:			
Retail sales	**$4,776,985**	$4,309,972	$4,288,097
Sales for resale --			
Non-affiliates	**246,545**	259,376	270,678
Affiliates	**166,245**	174,855	98,323
Other revenues	**181,033**	169,304	165,362
Total operating revenues	**5,370,808**	4,913,507	4,822,460
Operating Expenses:			
Fuel	**1,232,496**	1,103,963	1,002,703
Purchased power --			
Non-affiliates	**304,978**	258,621	264,814
Affiliates	**671,098**	516,944	419,839
Other operations	**902,167**	827,972	848,436
Maintenance	**498,114**	419,206	476,962
Depreciation and amortization	**275,488**	349,984	403,507
Taxes other than income taxes	**227,806**	212,827	201,857
Total operating expenses	**4,112,147**	3,689,517	3,618,118
Operating Income	**1,258,661**	1,223,990	1,204,342
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,659**	10,752	7,622
Interest income	**6,657**	15,625	3,857
Interest expense, net of amounts capitalized	**(182,370)**	(182,583)	(168,391)
Interest expense to affiliate trusts	**(44,565)**	-	-
Distributions on mandatorily redeemable preferred securities	**(15,839)**	(59,675)	(62,553)
Other income (expense), net	**(11,362)**	(10,551)	(9,259)
Total other income and (expense)	**(220,820)**	(226,432)	(228,724)
Earnings Before Income Taxes	**1,037,841**	997,558	975,618
Income taxes	**379,170**	366,311	357,319
Net Income	**658,671**	631,247	618,299
Dividends on Preferred Stock	**670**	670	670
Net Income After Dividends on Preferred Stock	**$658,001**	$630,577	$617,629

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003, and 2002

Georgia Power Company 2004 Annual Report

	2004	2003	2002
		(in thousands)	
Operating Activities:			
Net income	**$ 658,671**	$ 631,247	$ 618,299
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**361,958**	424,321	459,563
Deferred income taxes and investment tax credits, net	**251,623**	199,265	65,550
Deferred expenses - affiliates	**(10,563)**	(7,399)	(11,575)
Allowance for equity funds used during construction	**(26,659)**	(10,752)	(7,622)
Pension, postretirement, and other employee benefits	**2,636**	(16,162)	(64,771)
Tax benefit of stock options	**9,701**	11,649	8,184
Hedge settlements	**(12,394)**	(11,250)	860
Other, net	**(27,624)**	16,591	(82,190)
Changes in certain current assets and liabilities --			
Receivables, net	**(225,454)**	(4,870)	68,527
Fossil fuel stock	**(46,730)**	(17,490)	82,711
Materials and supplies	**618**	(7,677)	15,874
Other current assets	**(9,314)**	(2,352)	(18,880)
Accounts payable	**132,001**	(62,553)	64,902
Accrued taxes	**(64,563)**	52,348	(6,540)
Accrued compensation	**(6,664)**	(3,111)	(29,749)
Other current liabilities	**5,836**	19,845	45,915
Net cash provided from operating activities	**993,079**	1,211,650	1,209,058
Investing Activities:			
Gross property additions	**(786,314)**	(742,808)	(883,968)
Purchase of property from affiliates	**(339,750)**	(2)	-
Cost of removal net of salvage	**(21,756)**	(28,265)	(60,912)
Sale of property to affiliates	**-**	-	387,212
Change in construction payables, net of joint owner portion	**413**	(32,223)	(7,411)
Other	**31,503**	17,124	37,557
Net cash used for investing activities	**(1,115,904)**	(786,174)	(527,522)
Financing Activities:			
Increase (decrease) in notes payable, net	**70,956**	(220,400)	(389,860)
Proceeds --			
Senior notes	**600,000**	1,000,000	500,000
Mandatorily redeemable preferred securities	**200,000**	-	740,000
Capital contributions from parent company	**260,068**	40,809	165,299
Redemptions --			
First mortgage bonds	**-**	-	(1,860)
Pollution control bonds	**-**	-	(7,800)
Senior notes	**(200,000)**	(665,000)	(330,000)
Mandatorily redeemable preferred securities	**(200,000)**	-	(589,250)
Capital distributions to parent company	**-**	-	(200,000)
Payment of preferred stock dividends	**(654)**	(696)	(721)
Payment of common stock dividends	**(565,500)**	(565,800)	(542,900)
Other	**(17,247)**	(22,563)	(30,831)
Net cash provided from (used for) financing activities	**147,623**	(433,650)	(687,923)
Net Change in Cash and Cash Equivalents	**24,798**	(8,174)	(6,387)
Cash and Cash Equivalents at Beginning of Period	**8,699**	16,873	23,260
Cash and Cash Equivalents at End of Period	**$ 33,497**	$ 8,699	$ 16,873
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $8,920, $5,428, and $9,368 capitalized, respectively)	**$228,190**	$215,463	$203,707
Income taxes (net of refunds)	**127,115**	145,048	326,698

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

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BALANCE SHEETS
At December 31, 2004 and 2003
Georgia Power Company 2004 Annual Report

Assets	**2004**	2003
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 33,497**	$ 8,699
Receivables --		
Customer accounts receivable	**317,937**	261,771
Unbilled revenues	**140,027**	117,327
Under recovered regulatory clause revenues	**345,542**	151,447
Other accounts and notes receivable	**94,377**	101,783
Affiliated companies	**17,042**	52,413
Accumulated provision for uncollectible accounts	**(7,100)**	(5,350)
Fossil fuel stock, at average cost	**184,267**	137,537
Vacation pay	**57,372**	50,150
Materials and supplies, at average cost	**270,422**	271,040
Prepaid expenses	**32,696**	114,882
Other	**25,260**	83
Total current assets	**1,511,339**	1,261,782
Property, Plant, and Equipment:		
In service	**18,681,533**	18,171,862
Less accumulated provision for depreciation	**7,217,607**	6,898,725
	11,463,926	11,273,137
Nuclear fuel, at amortized cost	**124,745**	129,056
Construction work in progress	**766,140**	341,783
Total property, plant, and equipment	**12,354,811**	11,743,976
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**66,192**	38,714
Nuclear decommissioning trusts, at fair value	**459,194**	423,319
Other	**66,775**	52,386
Total other property and investments	**592,161**	514,419
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**505,664**	509,887
Prepaid pension costs	**450,270**	405,164
Unamortized debt issuance expense	**77,925**	75,245
Unamortized loss on reacquired debt	**176,825**	177,707
Other regulatory assets	**72,639**	84,901
Other	**80,704**	77,673
Total deferred charges and other assets	**1,364,027**	1,330,577
Total Assets	**$15,822,338**	$14,850,754

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

BALANCE SHEETS

At December 31, 2004 and 2003

Georgia Power Company 2004 Annual Report

Liabilities and Stockholder's Equity	2004	2003
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ **452,498**	$ 2,304
Notes payable	**208,233**	137,277
Accounts payable --		
Affiliated	**194,253**	134,884
Other	**310,763**	238,069
Customer deposits	**115,661**	103,756
Accrued taxes --		
Income taxes	**78,269**	39,970
Other	**129,520**	166,892
Accrued interest	**74,529**	70,844
Accrued vacation pay	**44,894**	38,206
Accrued compensation	**127,340**	134,004
Other	**75,699**	105,234
Total current liabilities	**1,811,659**	1,171,440
Long-term Debt (See accompanying statements)	**3,709,852**	3,762,333
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	**969,073**	-
Mandatorily Redeemable Preferred Securities (See accompanying statements)	**-**	940,000
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,556,040**	2,439,373
Deferred credits related to income taxes	**170,973**	186,625
Accumulated deferred investment tax credits	**300,018**	312,506
Employee benefit obligations	**331,002**	282,833
Asset retirement obligations	**504,515**	475,585
Other cost of removal obligations	**411,692**	412,161
Miscellaneous regulatory liabilities	**92,611**	249,687
Other	**59,733**	63,431
Total deferred credits and other liabilities	**4,426,584**	4,422,201
Total Liabilities	**10,917,168**	10,295,974
Preferred Stock (See accompanying statements)	**14,609**	14,569
Common Stockholder's Equity (See accompanying statements)	**4,890,561**	4,540,211
Total Liabilities and Stockholder's Equity	**$15,822,338**	$14,850,754
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2004 and 2003
Georgia Power Company 2004 Annual Report

	2004	2003	2004	2003
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	**$ 150,000**	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	**300,000**	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	-		
Variable rate (2.48% at 1/1/05) due 2009	**150,000**	-		
4.00% to 6.70% due 2010-2044	**1,225,000**	1,100,000		
Total long-term notes payable	**2,400,000**	2,000,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
1.08% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (1.24% to 2.30% at 1/1/05) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**76,982**	79,286		
Unamortized debt premium (discount), net	**(522)**	(539)		
Total long-term debt (annual interest requirement -- $172.7 million)	**4,162,350**	3,764,637		
Less amount due within one year	**452,498**	2,304		
Long-term debt excluding amount due within one year	**3,709,852**	3,762,333	**38.7%**	40.6%
Long-term Debt Payable to Affiliated Trusts:				
4.875% through 2007 due 2042*	**309,279**	-		
5.875% to 7.125% due 2042 to 2044	**659,794**	-		
Total long-term debt payable to affiliated trusts (annual interest requirement -- $59.5 million)	**969,073**	-	**10.1**	0.0
Mandatorily Redeemable Preferred Securities:				
$25 liquidation value --				
6.85% due 2029	**-**	200,000		
7.125% due 2042	**-**	440,000		
$1,000 liquidation value -- 4.875% through 2007 due 2042*	**-**	300,000		
Total mandatorily redeemable preferred securities	**-**	940,000	**0.0**	10.2
Cumulative Preferred Stock:				
$100 stated value at 4.60% (annual dividend requirement -- $0.7 million)	**14,609**	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	**2,478,268**	2,208,538		
Retained earnings	**2,102,798**	2,010,297		
Accumulated other comprehensive income (loss)	**(34,755)**	(22,874)		
Total common stockholder's equity	**4,890,561**	4,540,211	**51.0**	49.0
Total Capitalization	**$9,584,095**	$9,257,113	**100.0%**	100.0%

*The fixed rate thereafter is determined through remarketings for specific periods of varying length or 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, 2004, 2003, and 2002
Georgia Power Company 2004 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2001	$344,250	$2,182,597	$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**	**2,156,080**	**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**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	**658,001**	-	**658,001**
Capital contributions from parent company	-	**269,769**	-	-	**269,769**
Other comprehensive income (loss)	-	-	-	**(11,881)**	**(11,881)**
Cash dividends on common stock	-	-	**(565,500)**	-	**(565,500)**
Other	-	**(39)**	-	-	**(39)**
Balance at December 31, 2004	**$344,250**	**$2,478,268**	**$2,102,798**	**$(34,755)**	**$4,890,561**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2004, 2003, and 2002
Georgia Power Company 2004 Annual Report

	2004	2003	2002
		(in thousands)	
Net income after dividends on preferred stock	**$658,001**	$630,577	$617,629
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(3,861), $(5,133) and $(4,853), respectively	**(6,122)**	(8,138)	(7,693)
Change in fair value of marketable securities, net of tax of $(114)	**(181)**	-	-
Changes in fair value of qualifying hedges, net of tax of $(5,046), $(3,241) and $(2,502), respectively	**(7,999)**	(5,550)	(3,555)
Less: Reclassification adjustment for amounts included in net income, net of tax of $1,528, $1,208 and $-, respectively	**2,421**	2,217	(2)
Total other comprehensive income (loss)	**(11,881)**	(11,471)	(11,250)
Comprehensive Income	**$646,120**	$619,106	$606,379

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (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 (SouthernLINC Wireless), 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. 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 the subsidiary companies. SouthernLINC Wireless 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 various other energy-related businesses. 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, as amended (PUHCA). Both Southern Company and its subsidiaries are subject to the regulatory provisions of the PUHCA. In addition, the Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). 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 those 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 $292 million in 2004, $303 million in 2003, and $318 million in 2002. 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 $311 million in 2004, $289 million in 2003, and $301 million in 2002.

The Company has an agreement with Southern Power under which the Company operates and maintains Southern Power owned plants Dahlberg, Franklin, Wansley, and Stanton at cost. Reimbursements under these agreements with Southern Power amounted to $4.9 million in 2004, $5.3 million in 2003, and $5.3 million in 2002.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.7

million in 2004, $7.4 million in 2003 and $5.9 million in 2002.

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 $53 million in 2004 and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $163 million in 2004 and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Purchased power costs were $282 million, $203 million and $128 million in 2004, 2003 and 2002, respectively. Additionally, the Company recorded $11 million and $7 million of prepaid capacity expenses included on the balance sheets at December 31, 2004 and 2003, respectively. See Note 7 under "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 $6.8 million in 2004, $4.9 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 $3.3 million in 2004, $3.7 million in 2003, and $2.2 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 (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

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 Commitments" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. 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 costs and amounts billed in current regulated 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 Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also 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 $73 million in 2004, $74 million in 2003, and $71 million in 2002. The Company has contracts with the 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 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 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. 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.

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. This assessment is being paid over a 15-year period, ending in 2008. 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, 2004 under this law to be approximately $7 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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.9 million, $12.0 million, and $4.7 million were recorded on the Company's books in 2004, 2003 and 2002, respectively.

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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2004	2003	Note
	(in millions)		
Deferred income tax charges	$ 506	$ 510	(a)
Premium on reacquired debt	177	178	(b)
Corporate building lease	53	54	(f)
Vacation pay	57	50	(d)
Postretirement benefits	20	23	(f)
DOE assessments	10	13	(c)
Generating plant outage costs	40	49	(h)
Other regulatory assets	11	1	(f)
Asset retirement obligation	(20)	(16)	(a)
Other cost of removal obligations	(412)	(412)	(a)
Accelerated cost recovery	-	(111)	(e)
Deferred income tax credits	(171)	(187)	(a)
Environmental remediation reserve	(22)	(21)	(g)
Purchased power	-	(77)	(e)
Other regulatory liabilities	(6)	(3)	(f)
Total	$ 243	$ 51	

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 tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 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 Georgia PSC.

(g) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Rate Orders."

(h) See "Property, Plant, and Equipment" herein.

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 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 2.6 percent in 2004, 2.7 percent in 2003, and 2.9 percent in 2002. Under a new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), the depreciation rates have been revised by the Georgia PSC. 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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. 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, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. 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 recorded 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

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 costs 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. Although 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, the Company has received accounting guidance from the Georgia PSC allowing such treatment. Accordingly, the accumulated removal costs for other obligations previously accrued will continue to be reflected on the balance sheets 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, 2004 was $459 million. In addition, the Company has recognized 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, liabilities for the removal of these facilities have not been 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. In 2003, the Company revised the estimated cost to retire plants Hatch and Vogtle as a result of a new 2003 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" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2004	2003
	(in millions)	
Balance beginning of year	$476	$469
Liabilities incurred	-	-
Liabilities settled	(2)	-
Accretion	31	31
Cash flow revisions	-	(24)
Balance end of year	$505	$476

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future 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 Georgia PSC 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 Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only 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 based on the most current study as of December 31, 2004 for 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 these estimates.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2004 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2004	$ 7	$ 2
Accumulated provisions:		
External trust funds, at fair value	$294	$165
Internal reserves	-	2
Total	$294	$167

Based on the 2001 Retail Rate Plan, effective January 1, 2002, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $9 million. This amount was based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Effective January 1, 2005, the Georgia PSC has ordered the annual decommissioning costs for ratemaking be decreased from $9 million to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. 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 Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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. For the years 2004, 2003, and 2002, the average AFUDC rates were 8.22 percent, 5.51 percent, and 3.79 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.9 percent of net income after dividends on preferred stock for 2004 and less than 3 percent for 2003 and 2002.

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. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the 2001 Retail Rate Plan, 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, as compared with 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 provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Rate Orders" and "Plant McIntosh Construction Project" for information regarding the disallowance of Plant McIntosh costs under the 2004 Retail Rate Plan.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. These costs are expected to be recovered through regular monthly accruals which total $6.3 million annually under the 2004 Retail Rate Plan.

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 costs 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 of Southern Company's common stock 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.

The pro forma impact of fair-value accounting for options granted on earnings is as follows:

Net Income	As Reported	Pro Forma
	(in thousands)	
2004	**$658,001**	**$654,482**
2003	$630,577	$626,738
2002	$617,629	$613,483

The estimated fair value of stock options granted in 2004, 2003, and 2002 were derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted coverage. Fair values of stock options are as follows:

	2004	2003	2002
Interest rate	**3.10%**	2.70%	2.80%
Average expected life of stock options (in years)	**5.0**	4.3	4.3
Expected volatility of common stock	**19.60%**	23.60%	26.30%
Expected annual dividends on common stock	**$1.40**	$1.37	$1.34
Weighted average fair value of stock options granted	**$3.29**	$3.59	$3.37

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, 2004	**$5,055**	**$5,125**
At December 31, 2003	$3,685	$3,739
Preferred securities:		
At December 31, 2004	**-**	**-**
At December 31, 2003	$940	$976

The fair values were based on either closing market prices or closing prices of comparable instruments. See "Variable Interest Entities" herein and Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for further information.

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 value of marketable securities and qualifying cash flow hedges, and changes in additional minimum pension liability, less income taxes less reclassifications for amounts included in net income.

Variable Interest Entities

On March 31, 2004, the Company prospectively adopted FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities," which requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. The adoption of Interpretation No. 46R had no impact on the net income of the Company. However, as a result of the adoption, the Company deconsolidated certain wholly-owned trusts established to issue preferred securities since the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts on the balance sheets. This treatment resulted in a $29 million increase in both total assets and total liabilities as of March 31, 2004.

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 of 1974, as amended (ERISA), requirements. No contributions to the plan are expected for the year ending December 31, 2005. 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 Georgia PSC and the FERC. For the year ended December 31, 2005, such contributions are expected to total approximately $7.7 million.

The measurement date for plan assets and obligations is September 30 for each year.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.7 billion in 2004 and $1.6 billion in 2003. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets were as follows:

	Projected Benefit Obligation	
	2004	2003
	(in millions)	
Balance at beginning of year	**$1,727**	$1,564
Service cost	**42**	38
Interest cost	**101**	100
Benefits paid	**(85)**	(83)
Plan amendments	**1**	6
Actuarial loss	**99**	102
Balance at end of year	**$1,885**	$1,727

	Plan Assets 2004	2003
	(in millions)	
Balance at beginning of year	**$2,055**	$1,838
Actual return on plan assets	**207**	294
Benefits paid	**(81)**	(77)
Balance at end of year	**$2,181**	$2,055

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal 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	2004	2003
Domestic equity	**37%**	**36%**	37%
International equity	**20**	**20**	20
Fixed income	**26**	**26**	24
Real estate	**10**	**10**	11
Private equity	**7**	**8**	8
Total	**100%**	**100%**	100%

The reconciliations of the funded status with the accrued pension costs recognized in the balance sheets were as follows:

	2004	2003
	(in millions)	
Funded status	**$295**	$328
Unrecognized transition amount	**(8)**	(13)
Unrecognized prior service cost	**108**	118
Unrecognized net actuarial gain (loss)	**21**	(66)
Prepaid pension asset, net	**$416**	$367

The prepaid pension asset, net is reflected in the balance sheets in the following line items:

	2004	2003
	(in millions)	
Prepaid pension asset	**$450**	$405
Employee benefit obligations	**(89)**	(82)
Other property and investments - other	**19**	18
Accumulated other comprehensive income	**36**	26
Prepaid pension asset, net	**$416**	$367

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

	2004	2003	2002
	(in millions)		
Service cost	**$ 42**	$ 38	$ 36
Interest cost	**101**	100	107
Expected return on plan assets	**(180)**	(179)	(179)
Recognized net gain	**(5)**	(19)	(27)
Net amortization	**7**	6	4
Net pension (income)	**$ (35)**	$(54)	$ (59)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2004, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2005	$ 83
2006	83
2007	86
2008	89
2009	93
2010 to 2014	$568

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	
	2004	2003
	(in millions)	
Balance at beginning of year	**$723**	$627
Service cost	**10**	9
Interest cost	**41**	40
Benefits paid	**(31)**	(29)
Actuarial loss	**42**	76
Plan amendments	**(59)**	-
Balance at end of year	**$726**	$723

	Plan Assets	
	2004	2003
	(in millions)	
Balance at beginning of year	**$265**	$199
Actual return on plan assets	**32**	36
Employer contributions	**33**	59
Benefits paid	**(31)**	(29)
Balance at end of year	**$299**	$265

Postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal 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	**2004**	2003
Domestic equity	43%	**42%**	42%
International equity	20	**23**	21
Domestic fixed income	19	**19**	-
Global fixed income	13	**11**	32
Real estate	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The accrued postretirement costs recognized in the balance sheets were as follows:

	2004	2003
	(in millions)	
Funded status	**$(428)**	$(458)
Unrecognized transition obligation	**78**	87
Unrecognized prior service cost	**27**	91
Unrecognized net loss	**203**	171
Fourth quarter contributions	**15**	9
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(100)

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

	2004	2003	2002
	(in millions)		
Service cost	**$ 10**	$ 9	$ 8
Interest cost	**41**	40	40
Expected return on plan assets	**(25)**	(24)	(20)
Net amortization	**18**	16	15
Net postretirement cost	**$ 44**	$ 41	$ 43

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 by approximately $5 million and is expected to have a similar impact on future expenses. The subsidy's impact on the postretirement medical plan APBO was a reduction of approximately $72 million. However, the ultimate impact on future periods is subject to federal regulations governing the subsidy created in the Medicare Act which are being finalized.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2005	**$ 28**	$ -	$ 28
2006	**31**	(3)	28
2007	**34**	(3)	31
2008	**37**	(4)	33
2009	**41**	(4)	37
2010 to 2014	**$257**	$(28)	$229

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

	2004	2003	2002
Discount	**5.75%**	6.00%	6.50%
Annual salary increase	**3.50**	3.75	4.00
Long-term return on plan assets	**8.50**	8.50	8.50

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 obligation was a weighted average medical care cost trend rate of 11.0 percent for 2004, decreasing gradually to 5.0 percent through the year 2012, 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, 2004, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$75	$59
Service and interest costs	5	4

Employee Savings Plan

The Company also 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 2004, 2003, and 2002 were $18 million, $18 million, and $17 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

On December 21, 2004, the Georgia PSC voted to approve the 2004 Retail Rate Plan. Under the terms of the 2004 Retail Rate Plan, earnings will be evaluated against a retail return on common equity range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates will be increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability.

In the 2004 Retail Rate Plan, the Georgia PSC also approved the transfer of the Plant McIntosh construction project, which is scheduled for completion in June 2005, to the Company and Savannah Electric at a total fair market value of approximately $385 million. This value reflects an approximate $16 million disallowance, of which $13 million is attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified the total completion cost of $547 million for the project. The amount of the disallowance will be adjusted accordingly based on the actual completion cost of the project. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirement impact will be reflected in the Company's rates evenly over the three years ending 2007.

The Company will not file for a general base rate increase unless its projected retail return on common equity falls below 10.25 percent. The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs. Under the 2004 Retail Rate Plan, this regulatory liability will be amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures will be charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were 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 were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003 and 2002 were within the common equity range.

Under the 2001 Retail Rate Plan, 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 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Retail Fuel Hedging Program

Effective in January 2003, the Georgia PSC approved an order 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 total net gains. In 2004, the Company had a total net gain of $7.4 million, of which the Company retained $1.9 million.

Fuel Cost Recovery

On August 19, 2003, the Georgia PSC issued an order allowing 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 represented an average annual increase in rates paid by customers of approximately 1.6 percent. In recent months, the Company has experienced higher than expected fuel costs since the order was issued. Those higher fuel costs have increased the under recovered fuel costs. On February 18, 2005, the Company filed a request with the Georgia PSC for a fuel cost recovery rate increase. In the ordinary course, these new rates will be effective June 1, 2005 following a hearing before and approval by the Georgia PSC. In its filing, the Company asked that the Georgia PSC accept the new rate, effective April 1, 2005, prior to a formal hearing on the Company's request. This action, if taken by the Georgia PSC, would serve to mitigate expected increases in the under recovered balance during April and May, but will not preclude the Georgia PSC from subsequently adjusting the rates. The requested increase, representing an annual increase in revenues of approximately 11.7 percent, will allow for the recovery of fuel costs based on an estimate of future fuel costs, as well as the collection of the existing under recovery of fuel costs. The Company's under recovered fuel costs as of January 31, 2005 totaled $390 million. The Georgia

PSC will examine the Company's fuel expenditures and determine whether the proposed fuel cost recovery rate is just and reasonable before issuing its decision in May 2005. The final outcome of the filing cannot be determined at this time.

Nuclear Performance Standards

Through December 31, 2004, the Company has operated in accordance with the nuclear performance standard the Georgia PSC adopted 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. Such amounts flow through the fuel cost recovery mechanism. Any award or penalty for the 2002-2004 evaluation period will not be known until the second quarter of 2005.

Effective January 1, 2005, the Georgia PSC has discontinued the nuclear performance standard.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against the Company, alleging violations of the New Source Review (NSR) provisions of the Clean Air Act and related state laws 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 was stayed in the spring of 2001 during the appeal of a similar NSR enforcement action against the Tennessee Valley Authority (TVA) before the U.S. Court of Appeals for the Eleventh Circuit. In June 2003, the Court of Appeals issued its ruling in the TVA case, dismissing the appeal for reasons unrelated to the issues in the case pending against the Company. In May 2004, the U.S. Supreme Court denied the EPA's petition for review of the case. At this time, no party to the case against the Company has sought to reopen the case, which remains administratively closed in the U.S. District Court for the Northern District of Georgia.

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 utilities considered to be routine or otherwise not subject to NSR. District courts addressing these cases have, to date, issued opinions that reached conflicting conclusions.

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 maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter 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 possibly financial condition if such costs are not recovered through regulated rates.

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 (RMRR) exclusion. A coalition of states and environmental organizations has filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. The October 2003 RMRR rules have been stayed by the Court of Appeals pending its review of the rules. 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, related legal challenges and potential rulemakings by the State of Georgia cannot be determined at this time.

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 for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the 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 nitrogen oxide emission offset requirements, and (4) violation of 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.

The court has concluded the liability phase of the action. The court ruled in favor of the Company on the allegations regarding the hazardous air pollutants, the allegations regarding emission offsets, and a majority of the allegations regarding the permit provision that requires the combined cycle units to operate above certain levels. The court ruled in favor of the plaintiffs on a majority of the opacity incidents. The Company has filed a petition for review of the decision with the U.S. Court of Appeals for the Eleventh Circuit. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate remedy trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the 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.

Environmental Remediation

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 $35 million in cumulative expenses through December 31, 2004 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, 2004, 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 of the Company's 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, an additional indirect subsidiary of Southern Company, Southern Company Energy Solutions, was named a defendant.

In October 2001, the district court denied the plaintiffs' motion for class certification. The U.S. Court of Appeals for the Eleventh Circuit subsequently denied plaintiff's petition seeking permission to file an appeal of the October 2001 decision. In March 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. In April 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. On November 10, 2004, a three-judge panel of the U.S. Court of Appeals for the Eleventh Circuit issued an order affirming in all respects the district court's rulings. On December 1, 2004, the plaintiffs filed a petition for rehearing seeking a review of the November 2004 order by the entire Eleventh Circuit panel of judges. If this petition is denied, the plaintiffs will have 90 days from the date of the court's order denying the petition within which to file a petition for writ of certiorari to the U.S. Supreme Court. 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, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief.

On January 14, 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company is appealing this ruling to the Georgia Court of Appeals. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit. An adverse outcome in these matters could result in substantial judgments; however, the final outcome 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, 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 it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. On January 12, 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. 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.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to nonaffiliates at market-based prices. 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, the retail operating companies, and Southern Power and found them to be "pivotal suppliers" in their retail service territories and ordered the implementation of certain mitigation measures. Southern Company and others sought rehearing of the FERC order, and the FERC delayed implementation of certain mitigation measures. In April 2004, the FERC issued an order that abandoned the SMA test and adopted a new interim analysis for measuring generation market power. This new interim approach requires utilities to submit a pivotal supplier screen and a wholesale market share screen. If the applicant does not pass both screens, there will be a rebuttable presumption regarding generation market power. The FERC's order also sets forth procedures for rebutting these presumptions and addresses mitigation measures for those entities that are found to have market power. In the absence of specific mitigation measures, the order includes several cost-based mitigation measures that would apply by default. The FERC also initiated a new rulemaking proceeding that, among other things, will adopt a final methodology for assessing generation market power.

In July 2004, the FERC denied Southern Company's request for rehearing, along with a number of others, and reaffirmed the interim tests that it adopted in April. In August 2004, Southern Company submitted a filing to the FERC which included results showing that Southern Company passed the pivotal supplier screen for all markets and the wholesale market share screen for all markets except the Southern Company retail service territory. Southern Company also submitted other analyses to demonstrate that it lacks generation market power. On December 17, 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within the Southern Company retail service territory. The ability to charge market-based rates in other markets is not at issue. As directed by this order, on February 15 2005, Southern Company submitted additional information related to generation dominance in the retail service territory. Any new market-based rate transactions in Southern Company's retail service territory entered into after February 27, 2005 will be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Southern Company, along with other utilities, has also filed an appeal of the FERC's April and July 2004 orders with the U.S. Court of Appeals for the District of Columbia Circuit. The FERC has asked the court to dismiss the appeal on the grounds that it is premature.

In the event that the FERC's default mitigation measures are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which is scheduled to be completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. The ultimate outcome of any additional FERC action cannot be determined at this time.

As directed by the Georgia PSC order, on June 3, 2004, the Company and Savannah Electric filed an application to amend the resource certificate granted by the Georgia PSC in 2002. In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflects an approximate $16 million disallowance, of which $13 million is attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. The amount of the disallowance will be adjusted accordingly based on the actual completion cost of the project. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See "Retail Rate Orders" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of 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:

	2004	2003	2002
		(in millions)	
Energy	**$51**	$55	$53
Capacity	**36**	34	32
Total	**$87**	$89	$85

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 combustion-turbine units 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, 2004, 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%	$3,304*	$1,756
Plant Hatch (nuclear)	50.1	932	485
Plant Wansley (coal)	53.5	394	164
Plant Scherer (coal)			
Units 1 and 2	8.4	114	53
Unit 3	75.0	561	259
Plant McIntosh Common Facilities (combustion-turbine)	75.0	34	4
Rocky Mountain (pumped storage)	25.4	169*	89
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

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 and a combined State of Georgia income tax return. Under a joint consolidated income tax allocation agreement, as required by the PUHCA, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $25 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2004.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the related $5.4 million deferred taxes reflected in Southern Power's future taxable income. This payable to Southern Power is included in Other Deferred Credits on the balance sheets at December 31, 2004.

The transfer of the Dahlberg, Wansley and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $13.3 million reflected in the Company's future taxable income. This receivable from Southern Power is included in Other Deferred Debits on the balance sheets at December 31, 2004.

At December 31, 2004, tax-related regulatory assets were $506 million and tax-related regulatory liabilities were $171 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:

	2004	2003	2002
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$116**	$143	$261
Deferred	**221**	181	60
	337	324	321
State:			
Current	**12**	24	31
Deferred	**30**	16	5
Deferred investment tax credits	**-**	2	-
Total	**$379**	$366	$357

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:

	2004	2003
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,050**	$1,966
Property basis differences	**577**	563
Other	**449**	329
Total	**3,076**	2,858
Deferred tax assets:		
Federal effect of state deferred taxes	**106**	96
Other property basis differences	**147**	156
Other deferred costs	**149**	160
Other	**52**	75
Total	**454**	487
Net deferred tax liabilities	**2,622**	2,37
Portion included in current (liabilities) assets, net	**(66)**	6
Accumulated deferred income taxes in the balance sheets	**$2,556**	$2,43

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 $12 million in 2004, $15 million in 2003, and $12 million in 2002. At December 31, 2004, 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:

	2004	2003	2002
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	2
Non-deductible book depreciation	1	1	1
Other	(2)	(2)	(1)
Effective income tax rate	37%	37%	37%

6. FINANCING

Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred 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 and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated 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 securities. At December 31, 2004, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities. The preferred securities are recognized as liabilities in the balance sheets.

Long-Term Debt Due Within One Year

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

	2004	2003
	(in millions)	
Capital lease	$ 2	$2
Senior notes	450	-
Total	$452	$2

Serial maturities through 2009 applicable to total long-term debt are as follows: $452 million in 2005; $153 million in 2006; $303 million in 2007; $3 million in 2008; and $279 million in 2009.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2004 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, 2004 and 2003, the Company had a capitalized lease obligation for its corporate headquarters building of $77 million and $79 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. At December 31, 2004 and 2003, the interest and lease amortization deferred on the balance sheets were $53 million and $54 million, respectively.

Bank Credit Arrangements

At the beginning of 2005, the Company had an unused credit arrangement with banks totaling $773.1 million. Of these facilities, $423.1 million expire at various times throughout 2005, with the remaining $350 million expiring in 2007. The facilities that expire in 2005 provide the option of converting borrowings into a two-year term loan. The agreements contain stated borrowing rates but also allow for competitive bid loans. All the agreements require 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 arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. 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 $773.1 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, 2004 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, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2004. The amount of commercial paper outstanding at December 31, 2003 was $137 million. During 2004, the peak amount of commercial paper outstanding was $391.5 million and the average amount outstanding was $130.7 million. The average annual interest rate on commercial paper in 2004 was 1.27 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 Georgia PSC. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2004 and 2003.

At December 31, 2004, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in millions)
Regulatory liabilities, net	$5.7
Other comprehensive income	-
Net income	0.1
Total fair value	$5.8

The fair value gain or loss for cash flow hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2007.

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. In addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2004, the Company had interest derivatives outstanding with net fair value losses as follows:

Cash Flow Hedges

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/ (Loss)
		(in millions)	
2005	1.56%	$50	$0.1
2005	1.96	250	0.3
2005-2007	2.35-3.85[1]	400	0.6
2006	6.00[2]	150	(0.1)
2015	4.66	250	0.7
2015	5.03	100	(0.9)

1. Capped rate based on formula approximating the yield on short rate tax-exempt, auction rate securities.
2. Costless collar with cap rate of 6.00 percent.

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 2004, the Company settled losses totaling $12.4 million upon termination of certain interest derivatives at the same time it issued debt. For the years 2004 and 2003, approximately $3.9 million and $3.4 million, respectively, were reclassified from other comprehensive income to interest expense. For 2002, the amounts reclassified were immaterial. For 2005, pre-tax losses of approximately $0.4 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2017. Subsequent to December 31, 2004, the Company terminated an interest rate swap with a notional amount of $250 million at a gain of $1.2 million. The gain will be amortized to interest expense over a 10-year period.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $911 million, $1.1 billion, and $1.2 billion in 2005, 2006, and 2007, respectively. These amounts include $40 million, $33 million, and $28 million in 2005, 2006, and 2007, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel 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, 2004, significant purchase commitments were outstanding in connection with the construction program.

The Company currently has under construction Plant McIntosh Units 10 and 11 scheduled for completion in June 2005. In addition, construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, are ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combine cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $182 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has entered into a LTSA with GE to provide all necessary labor and parts for neutron monitoring at Plant Hatch for a period of 10 years. Total payments to GE under this agreement are currently estimated at $14.9 million, of which $7.4 is expected to be billed to the joint owners.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. 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 Exchange future prices at December 31, 2004. Also the Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2004 were as follows:

Year	Natural Gas	Coal and Nuclear Fuel
	(in millions)	
2005	$ 248	$1,731
2006	237	1,617
2007	151	1,105
2008	200	552
2009	189	219
2010 and thereafter	1,669	96
Total commitments	$2,694	$5,320

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.

Purchased Power Commitments

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 $55 million, $57 million, and $57 million in 2004, 2003, and 2002, respectively. The current projected Plant Vogtle capacity payments are:

Year	Capacity Payments
	(in millions)
2005	$ 56
2006	55
2007	54
2008	54
2009	54
2010 and thereafter	315
Total	$588

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, 2004 were as follows:

Year	Affiliated	Non-Affiliated
	(in millions)	
2005	$ 205	$ 78
2006	205	86
2007	205	87
2008	205	88
2009	205	67
2010 and thereafter	567	340
Total	$1,592	$746

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2004, $36 million for 2003, and $35 million for 2002. At December 31, 2004, estimated minimum rental commitments for these noncancelable operating leases were as follows:

	Minimum Obligations		
Year	Rail Cars	Other	Total
		(in millions)	
2005	$ 15	$17	$ 32
2006	16	13	29
2007	13	10	23
2008	14	8	22
2009	13	7	20
2010 and thereafter	55	8	63
Total	$126	$63	$189

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 2011, and the Company's maximum obligation is $72 million. 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 Georgia PSC.

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, 2004, the outstanding loans guaranteed by the Company were $5.1 million and loan loss reserves of $1.1 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. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of its employees ranging from line management to executives. As of December 31, 2004, 1,547 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2002 to 2004 for the options granted to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2001	6,597,517	$17.41
Options granted	1,781,940	25.27
Options canceled	(40,607)	16.67
Options exercised	(1,160,253)	15.18
Balance at December 31, 2002	7,178,597	19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	**7,150,981**	**21.92**
Options granted	**1,434,915**	**29.50**
Options canceled	**(5,802)**	**25.99**
Options exercised	**(1,450,309)**	**18.25**
Balance at December 31, 2004	**7,129,785**	**$24.19**

Options exercisable:	
At December 31, 2002	3,405,398
At December 31, 2003	3,956,234
At December 31, 2004	**4,304,091**

The following table summarizes information about options outstanding at December 31, 2004:

	Dollar Price Range of Options		
	13-20	20-26	26-32
Outstanding:			
Shares (in thousands)	**1,914**	**2,411**	**2,805**
Average remaining life (in years)	**5.6**	**6.8**	**8.6**
Average exercise price	**$17.42**	**$24.26**	**$28.76**
Exercisable:			
Shares (in thousands)	**1,914**	**1,906**	**483**
Average exercise price	**$17.42**	**$23.99**	**$28.01**

9. 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 $10.76 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 payment 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 b 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 $43 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.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2004 and 2003 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2004	**$1,199**	**$285**	**$144**
June 2004	**1,353**	**322**	**156**
September 2004	**1,582**	**486**	**287**
December 2004	**1,237**	**166**	**71**
March 2003	$1,126	$262	$133
June 2003	1,190	293	159
September 2003	1,487	490	265
December 2003	1,111	179	74

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

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	2004	2003	2002	2001	2000
Operating Revenues (in thousands)	**$5,370,808**	$4,913,507	$4,822,460	$4,965,794	$4,870,618
Net Income after Dividends on Preferred Stock (in thousands)	**$658,001**	$630,577	$617,629	$610,335	$559,420
Cash Dividends on Common Stock (in thousands)	**$565,500**	$565,800	$542,900	$527,300	$549,600
Return on Average Common Equity (percent)	**13.95**	14.05	13.99	14.12	13.66
Total Assets (in thousands)	**$15,822,338**	$14,850,754	$14,342,656	$14,447,973	$13,971,211
Gross Property Additions (in thousands)	**$1,126,064**	$742,810	$883,968	$1,389,751	$1,078,163
Capitalization (in thousands):					
Common stock equity	**$4,890,561**	$4,540,211	$4,434,447	$4,397,485	$4,249,544
Preferred stock	**14,609**	14,569	14,569	14,569	14,569
Mandatorily redeemable preferred securities	**-**	940,000	940,000	789,250	789,250
Long-term debt payable to affiliated trusts	**969,073**	-	-	-	-
Long-term debt	**3,709,852**	3,762,333	3,109,619	2,961,726	3,041,939
Total (excluding amounts due within one year)	**$9,584,095**	$9,257,113	$8,498,635	$8,163,030	$8,095,302
Capitalization Ratios (percent):					
Common stock equity	**51.0**	49.0	52.2	53.9	52.5
Preferred stock	**0.2**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**-**	10.2	11.1	9.6	9.7
Long-term debt payable to affiliated trusts	**10.1**	-	-	-	-
Long-term debt	**38.7**	40.6	36.5	36.3	37.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	a2
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
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	**1,801,426**	1,768,662	1,734,430	1,698,407	1,669,566
Commercial	**265,543**	258,276	250,993	244,674	237,977
Industrial	**7,676**	7,899	8,240	8,046	8,533
Other	**3,482**	3,434	3,328	3,239	3,159
Total	**2,078,127**	2,038,271	1,996,991	1,954,366	1,919,235
Employees (year-end):	**8,731**	8,714	8,837	9,048	8,860

N/A = Not Applicable.

	2004	2003	2002	2001	2000
Operating Revenues (in thousands):					
Residential	**$ 1,736,072**	$1,583,082	$1,600,438	$1,507,031	$1,535,684
Commercial	**1,812,096**	1,661,054	1,631,130	1,682,918	1,620,466
Industrial	**1,172,936**	1,012,267	1,004,288	1,106,420	1,154,789
Other	**55,881**	53,569	52,241	52,943	6,399
Total retail	**4,776,985**	4,309,972	4,288,097	4,349,312	4,317,338
Sales for resale - non-affiliates	**246,545**	259,376	270,678	366,085	297,643
Sales for resale - affiliates	**166,245**	174,855	98,323	99,411	96,150
Total revenues from sales of electricity	**5,189,775**	4,744,203	4,657,098	4,814,808	4,711,131
Other revenues	**181,033**	169,304	165,362	150,986	159,487
Total	**$5,370,808**	$4,913,507	$4,822,460	$4,965,794	$4,870,618
Kilowatt-Hour Sales (in thousands):					
Residential	**22,930,372**	21,778,582	22,144,559	20,119,080	20,693,481
Commercial	**28,014,357**	26,940,572	26,954,922	26,493,255	25,628,402
Industrial	**26,357,271**	25,703,421	25,739,785	25,349,477	27,543,265
Other	**602,202**	595,742	593,202	583,007	568,906
Total retail	**77,904,202**	75,018,317	75,432,468	72,544,819	74,434,054
Sales for resale - non-affiliates	**5,969,983**	8,835,804	8,069,375	8,110,096	6,463,723
Sales for resale - affiliates	**4,782,873**	5,844,196	3,962,559	3,133,485	2,435,106
Total	**88,657,058**	89,698,317	87,464,402	83,788,400	83,332,883
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.57**	7.27	7.23	7.49	7.42
Commercial	**6.47**	6.17	6.05	6.35	6.32
Industrial	**4.45**	3.94	3.90	4.36	4.19
Total retail	**6.13**	5.75	5.68	6.00	5.80
Sales for resale	**3.84**	2.96	3.07	4.14	4.43
Total sales	**5.85**	5.29	5.32	5.75	5.65
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,838**	12,421	12,867	11,933	12,520
Residential Average Annual Revenue Per Customer	**$972**	$903	$930	$894	$929
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**13,978**	13,980	14,059	14,474	15,114
Maximum Peak-Hour Demand (megawatts):					
Winter	**12,208**	13,153	11,873	11,977	12,014
Summer	**15,180**	14,826	14,597	14,294	14,930
Annual Load Factor (percent)	**61.5**	61.0	60.4	61.7	61.6
Plant Availability (percent):					
Fossil-steam	**90.3**	87.6	80.9	88.5	86.1
Nuclear	**94.8**	94.2	88.8	94.4	91.5
Source of Energy Supply (percent):					
Coal	**57.9**	58.6	59.5	58.5	62.3
Nuclear	**17.3**	16.8	16.2	18.1	17.4
Iydro	**1.5**	2.1	0.9	1.1	0.7
Oil and gas	**0.1**	0.3	0.3	0.4	1.8
'urchased power -					
From non-affiliates	**7.0**	7.5	6.3	7.8	8.1
From affiliates	**16.2**	14.7	16.8	14.1	9.7
'otal	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2004 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura

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

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Chief Executive Officer, Georgia Banking
Wachovia Corporation, Retired (12/2004)

Richard W. Ussery
Chairman of the Board
TSYS

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

Judy M. Anderson
Senior Vice President
Charitable Giving

William C. Archer, III
Executive Vice President
External Affairs

Mickey A. Brown
Executive Vice President
Customer Service Organization

C. B. (Mike) Harreld (resigned effective 3/17/05)
Executive Vice President, Chief Financial Officer,
Treasurer and Assistant Secretary

Cliff S. Thrasher (elected effective 3/17/05)
Executive Vice President, Chief Financial Officer
and Treasurer

Ronnie L. Bates (resigned effective 1/10/05)
Senior Vice President
Planning, Sales and Service

Richard L. Holmes
Senior Vice President
Metro Region, Diversity and Corporate Relations

Douglas E. Jones (elected effective 1/10/05)
Senior Vice President
Customer Service and Sales

James H. Miller, III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery (elected effective 2/16/05)
Vice President
Distribution

Chris C. Womack
Senior Vice President
Fossil and Hydro Power

DIRECTORS AND OFFICERS

W. Craig Barrs
Vice President
Community and Economic Development

Rebecca A. Blalock
Vice President
Information Resources

Walter Dukes (elected effective 2/16/05)
Vice President
East Region

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Customer Service

Jeff G. Franklin (elected effective 2/16/05)
Vice President
Northwest Region

O. Ben Harris
Vice President
Land

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

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

E. Lamont Houston
Vice President
Corporate Services

Charles H. Huling (elected effective 2/16/05)
Vice President
Environmental Affairs

Brian L. (Pete) Ivey (resigned effective 2/16/05)
Vice President
Administrative Services

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President
Human Resources

Jacki W. Lowe
Vice President
West Region

Terri H. Lupo (elected effective 2/16/05)
Vice President
South Region

Frank J. McCloskey
Vice President
Diversity and Corporate Relations

James E. Sykes, Jr.
Vice President
Northeast Region

Jeff L. Wallace
Vice President
Resource Policy and Market Planning

Thomas J. Wicker (elected effective 2/16/05)
Vice President
Central Region

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 retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to almost 2.1 million customers within its service area of approximately 57,000 square miles. In 2004, retail energy sales accounted for 88 percent of the Company's total sales of 88.7 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
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 the 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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Suite 5200
Atlanta, GA 30308