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2006 *Annual Report*

Georgia Power Company

GEORGIA POWER
A SOUTHERN COMPANY

CONTENTS

Georgia Power Company 2006 Annual Report

SUMMARY

	2006	2005	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$7,246**	$7,076	2.4
Operating expenses	**$5,736**	$5,628	1.9
Net income after dividends on preferred stock	**$787**	$744	5.8
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**84,556**	83,412	1.4
Sales for resale - non-affiliates	**12,314**	11,319	8.8
Sales for resale - affiliates	**5,495**	5,033	9.2
Total	**102,365**	99,764	2.6
Customers served at year-end *(in thousands)*	**2,306**	2,262	1.9
Peak-hour demand *(in megawatts)*	**17,159**	16,925	1.4
Capitalization Ratios *(percent):*			
Common stock equity	**53.1**	50.2	
Preferred stock	**0.4**	0.4	
Long-term debt payable to affiliated trusts	**8.6**	8.9	
Long-term debt (excluding amounts due within one year)	**37.9**	40.5	
Return on Average Common Equity *(percent)*	**13.80**	14.08	
Ratio of Earnings to Fixed Charges *(times)*	**4.72**	4.87	

LETTER TO INVESTORS
Georgia Power 2006 Annual Report

Georgia Power's operational and financial performance in 2006 produced banner results. We improved safety records across the board. We completed a merger with our sister company, Savannah Electric. We spent more with minority- and female-owned businesses than ever before, and despite a sweltering summer, reliability at our plants reached an all-time high.

On the safety front, we saw a 33 percent reduction in recordable accidents, a 46 percent drop in lost workday cases and a 34 percent decrease in preventable vehicle accidents. The Southern Company-wide Target Zero goal helped us create an atmosphere where safety is a top priority. We recently honored nine of our generating plants for operating 365 calendar days – all of 2006 – without a recordable accident. Those nine plants combined represent 900 employees. If we sustain our 2006 level of improvement during the next few years, we should achieve our goal of being an industry leader in safety.

Midway through the year, we completed the previously announced merger with Savannah Electric. The merger is expected to benefit customers by reducing costs and enhancing the future economic well-being of coastal Georgia.

We set an all-time peak for customer load of 17,159 megawatts on August 4 as temperatures climbed into the upper 90s. Despite record high temperatures and demand, our hydro and fossil plants far exceeded their equivalent forced outage rate goals.

Along with operational success, we're pleased to report strong financial results. With operating revenues of $7.2 billion, Georgia Power's 2006 earnings totaled $787 million, a $43 million, or 5.8 percent, increase from 2005. We earned a 13.8 percent total company return on average common equity during 2006. Georgia Power had net plant in service of $12.9 billion at the end of 2006, with total assets of $19.3 billion.

As for our supplier diversity program, Georgia Power spent $245 million with female- and minority-owned businesses in 2006 – more than 15 percent of all Georgia Power spending last year and the largest amount ever spent with participating companies. During the past five years, we increased our annual spending with female- and minority-owned companies from $80 million to $245 million, and we continue to seek additional business. The bottom line: We want our suppliers to mirror our customer base, and we're well on our way to achieving that goal.

As we reflect on 2006, there are several additional accomplishments to highlight:

- With an active hurricane season predicted last year, our employees made plans to be prepared. We upgraded our preparedness strategy, including drills and critiques designed to ensure any response needed would be fast and efficient.

- A new generating plant at the Seminole Road landfill in metro Atlanta's DeKalb County started providing power last fall for the company's first Green Energy offering. The 1.6-megawatt generators burn landfill gas and are expected to produce nearly 25 million kilowatt-hours annually.

- In partnership with the Georgia Department of Natural Resources (DNR), we planted 600 cypress trees around Lakes Harding and Oconee, which we hope will increase fish and wildlife activity on the lakes.

- Georgia Power representatives, as part of the Comprehensive Statewide Water Management Planning Act, took part in an on-going initiative to study the sustainable management and protection of the state's water resources.

- Working with the DNR and the U.S. Fish and Wildlife Service, we were involved in efforts to replenish the population of the robust redhorse, an endangered fish that lives in the Oconee and Ocmulgee rivers.

- Georgia Power's Community and Economic Development Department was recognized by *Site Selection* magazine as one of the top utilities in North America for economic development. Our efforts helped attract a projected 12,172 jobs and $3.9 billion in capital investment to Georgia, including South Korean automaker Kia's decision to build an assembly plant in West Point. Georgia Power also won a competitive bidding process to be the electric provider for the plant. Kia estimates that they will employ 2,800 workers directly and create 2,600 additional jobs with various suppliers. Slated to begin production in 2009, Kia expects to produce 300,000 vehicles yearly once it reaches full operation.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.3 million in 2006, a 1.9 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2006.

It's good not only to be able to look back on a year full of accomplishments but also to look ahead to what's in store for us this year. We're moving ahead by focusing on the basics: our more than 9,000 employees, 2.3 million customers and the communities we serve across the state.

These basic areas – along with reliable generation, transmission and distribution and an unwavering commitment to environmental responsibility – are paramount to our success.

Our employees are talented and committed to making Georgia Power successful. They are the reason for our strong performance this year.

Sincerely,

Michael D. Garrett
April 16, 2007

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 (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, 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, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included 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, such financial statements (pages 25 to 55) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 Georgia Power Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

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

Effective July 1, 2006, Savannah Electric and Power Company (Savannah Electric), which was also a wholly owned subsidiary of Southern Company, was merged into the Company. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements included herein now reflect the merger as though it had occurred on January 1, 2004. The supplemental selected financial and operating data reflect the merger as though it had occurred on January 1, 2002. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

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, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding (2004 Retail Rate Plan) that has provided earnings stability. This regulatory action also enabled the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a general rate case by July 1, 2007, which will determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. The Company also received regulatory orders to increase its fuel cost recovery rate effective June 1, 2005, July 1, 2006, and March 1, 2007.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro 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. The 2006 Peak Season EFOR of 0.99 percent is above target, a significant improvement over 2005 Peak Season EFOR of 1.42 percent. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. 2006 performance exceeded all targets on these reliability measures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2006 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2006 Target Performance	**2006 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile in customer surveys**
Peak Season EFOR	2.75% or less	**0.99%**
Net Income	$770 million	**$787 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis 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 2006 net income after dividends on preferred stock totaled $787 million representing a $43 million, or 5.8 percent, increase over 2005. Operating income increased in 2006 due to higher base retail revenues and wholesale non-fuel revenues, partially offset by higher non-fuel operating expenses and higher financing costs. The Company's 2005 earnings totaled $744 million representing a $61 million, or 9.0 percent, increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from retail rate increases effective January 1, 2005 and June 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $683 million representing a $29 million, or 4.4 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 resulting from a three-year retail rate plan approved by the Georgia Public Service Commission (PSC) in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
		(in millions)		
Operating revenues	**$ 7,246**	**$ 170**	$ 1,348	$ 499
Fuel	**2,233**	**296**	649	129
Purchased power	**1,145**	**(171)**	215	237
Other operations and maintenance	**1,560**	**(11)**	86	154
Depreciation and amortization	**499**	**(28)**	230	(74)
Taxes other than income taxes	**299**	**23**	33	16
Total operating expenses	**5,736**	**109**	1,213	462
Operating income	**1,510**	**61**	135	37
Total other income and (expense)	**(276)**	**(22)**	(19)	5
Income taxes	**442**	**(5)**	54	12
Net income	**792**	**44**	62	30
Dividends on preferred stock	**5**	**1**	1	1
Net income after dividends on preferred stock	**$ 787**	**$ 43**	$ 61	$ 29

Revenues

Operating revenues in 2006, 2005, and 2004 and the percent of change from the prior year are as follows:

	Amount		
	2006	2005	2004
		(in millions)	
Retail – prior year	**$6,065**	$5,119	$4,609
Change in –			
Base rates	**3**	201	–
Sales growth	**(4)**	136	161
Weather	**7**	23	32
Fuel cost recovery	**134**	586	317
Retail – current year	**6,205**	6,065	5,119
Sales for resale –			
Non-affiliates	**552**	525	252
Affiliates	**253**	275	172
Total sales for resale	**805**	800	424
Other operating revenues	**236**	211	185
Total operating revenues	**$7,246**	$7,076	$5,728
Percent change	**2.4%**	23.5%	9.5%

Retail base revenues of $3.8 billion in 2006 increased $7.0 million, or 0.2 percent, from 2005 primarily due to customer growth of 1.9 percent and more favorable weather, partially offset by lower market-driven rates to large commercial and industrial customers. Retail base revenues of $3.8 billion in 2005 increased by $360 million, or 10.6 percent, from 2004 primarily due to the retail rate increases effective January 1, 2005 and June 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.4 billion in 2004 increased by $192 million, or 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.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2006	2005	2004
		(in millions)	
Unit power sales --			
Capacity	**$ 33**	$ 33	$ 31
Energy	**38**	32	34
Other power sales --			
Capacity and other	**165**	155	75
Energy	**316**	305	112
Total	**$ 552**	$ 525	$ 252

Revenues from unit power sales contracts remained relatively constant in 2006, 2005, and 2004. Revenues from other non-affiliated sales increased $21 million, or 4.6 percent, and $273 million, or 146.0 percent, in 2006 and 2005, respectively, and decreased $13 million, or 6.5 percent, in 2004. The increase in 2006 was due to a 9.5 percent increase in the demand for kilowatt-hour (KWH) energy sales due to a new contract with an electrical membership corporation (EMC) that went into effect in April 2006. The increase in 2005 was primarily due to contracts with 30 EMCs that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $1 million and $73.2 million in 2006 and 2005, respectively.

Revenues from sales to affiliated companies within the Southern Company system 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 Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2006 and 2005, KWH energy sales to affiliates increased 9.2 percent and 2.2 percent, respectively, due to higher demand. However, revenues from these sales decreased by 8.3 percent in 2006 due to reduced cost per KWH delivered. Revenues increased 59.8 percent in 2005 due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.3 percent due to lower demand. However, the decline in associated revenues was only 5.0 percent due to higher fuel prices. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $24.6 million, or 11.6 percent, in 2006 primarily due to increased revenues of $14.1 million related to work performed for the other owners of the integrated transmission system (ITS) in the State of Georgia, higher customer fees of $4.6 million, and higher outdoor lighting revenues of $6.1 million due to a 5.5 percent increase in customers. Other operating revenues increased $26.1 million, or

14.1 percent, in 2005 from 2004, primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the ITS, higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in 2005 of $5.9 million. The increased transmission revenues in 2006 and 2005 did not have an impact on earnings since they were offset by associated transmission expenses. Other operating revenues increased $11.6 million, or 6.7 percent, in 2004 over 2003 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.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. **KWH** sales for 2006 and the percent change by year were as follows:

	KWH	Percent Change		
	2006	**2006**	2005	2004
	(in billions)			
Residential	**26.2**	**2.7%**	2.7%	5.5%
Commercial	**32.1**	**2.5**	6.0	4.1
Industrial	**25.6**	**(1.0)**	(5.0)	2.4
Other	**0.7**	**(10.5)**	(1.0)	1.6
Total retail	**84.6**	**1.4**	1.3	3.9
Sales for resale				
Non-affiliates	**12.3**	**8.8**	85.5	(32.2)
Affiliates	**5.5**	**9.2**	2.2	(18.3)
Total sales for resale	**17.8**	**8.9**	48.3	(26.6)
Total sales	**102.4**	**2.6**	6.9	(1.0)

Residential KWH sales increased 2.7 percent in 2006 over 2005 due to customer growth of 1.9 percent and more favorable weather. Commercial KWH sales increased 2.5 percent in 2006 over 2005 due to customer growth of 2.0 percent and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC. Industrial KWH sales decreased 1.0 percent due to a 3.4 percent decrease in the number of customers as a result of this reclassification.

Residential KWH sales increased 2.7 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.8 percent, and a 0.9 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.0 percent in 2005 when compared to 2004 due to more favorable weather, sustained economic strength, customer growth of 1.9 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.5 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.1 percent in 2004 due to an improved economy and a 3.0 percent increase in commercial customers. Industrial sales increased 2.4 percent in 2004 due to the improved economy.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Details of the Company's generation, fuel, and purchased power are as follows:

	2006	2005	2004
Total generation (billions of KWH)	**83.7**	82.7	73.6
Total purchased power (billions of KWH)	**23.7**	21.7	24.5
Sources of generation (percent)			
Coal	**74.4**	75.7	76.0
Nuclear	**18.2**	18.2	21.8
Gas	**6.2**	3.8	0.3
Hydro	**1.2**	2.3	1.9
Cost of fuel, generated (cents per net KWH)			
Coal	**2.58**	1.91	1.89
Nuclear	**0.47**	0.47	0.46
Gas	**5.76**	14.03	8.04
Average cost of fuel, generated (cents per net KWH)	**2.39**	2.12	1.58
Average cost of purchased power (cents per net KWH)	**5.90**	7.10	5.09

Fuel and purchased power expenses were $3.4 billion in 2006, an increase of $124 million, or 3.8 percent, above prior year costs. This increase was driven by a $181 million increase related to total KWH generated and purchased, partially offset by a $57 million decrease in the cost of fuel.

Fuel and purchased power expenses were $3.3 billion in 2005, an increase of $863 million, or 36.1 percent, above prior year costs. This increase was the result of an $868 million increase in the cost of fuel and a $5 million decrease related to total KWH generated and purchased.

Fuel and purchased power expenses were $2.4 billion in 2004, an increase of $365 million, or 18 percent, above prior year costs. This increase was the result of a $20 million increase in the cost of fuel and a $345 million increase related to total KWH generated and purchased.

The Company has entered into three power purchase agreements (PPAs) to purchase a total of approximately 1,000 megawatts (MW) annually from June 2009 through May 2024. These agreements were approved by the Georgia PSC on October 2, 2006. These agreements satisfy approximately 550 MW of growth, replace an existing 450 MW agreement that expires in May 2009, and are expected to result in higher operations and maintenance expenses that will be subject to recovery through future base rates.

While prices have moderated somewhat in 2006, 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 and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL — "PSC MATTERS — Fuel Cost Recovery."

Other Operations and Maintenance Expenses

In 2006, other operations and maintenance expenses decreased $11 million, or 0.7 percent, from the prior year. Maintenance for generating plants decreased $20.0 million in 2006 as a result of scheduled outages in 2005 offset by an increase of $18.2 million for transmission and distribution expenses related to load dispatching and overhead line maintenance. Also contributing to the decrease were decreased employee benefit expenses related to medical benefits and lower workers compensation expense of $23.2 million, partially offset by lower pension income of $13.7 million.

In 2005, other operations and maintenance expenses increased $86 million, or 5.8 percent. Maintenance for generating plant and transmission and distribution increased $27.5 million and $15.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.9 million related to pension and medical benefits and higher property insurance costs of $4.6 million resulting from storm damage also contributed to the increase. Customer assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies.

In 2004, other operations and maintenance expenses increased $155 million, or 11.6 percent, in part due to the timing of generating plant maintenance of $37.6 million and transmission and distribution maintenance of $39.6 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.

Depreciation and Amortization Expenses

Depreciation and amortization decreased $27.9 million, or 5.3 percent, in 2006 from the prior year due to the amortization of a regulatory liability related to the inclusion of certified PPAs in retail rates as ordered by the Georgia PSC under the terms of the 2004 Retail Rate Plan. This decrease was partially offset by a $15.9 million, or 3.2 percent, increase in depreciation expense in 2006 over 2005 due to an increase in plant in service. Depreciation and amortization increased $230 million, or 77.5 percent, in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million in 2004. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $22.8 million, or 8.3 percent, in 2006 primarily due to higher property taxes of $13.3 million as a result of an increase in property values and higher municipal gross receipts taxes of $9.1 million as a result of increased retail operating revenues. Taxes other than income taxes increased $33 million, or 13.6 percent, in 2005 primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased retail operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15.6 million, or 6.8 percent, in 2004 primarily due to higher municipal gross receipts taxes associated with increased retail operating revenues.

Allowance For Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) remained relatively constant in 2006 and 2005 and increased $18.1 million in 2004, primarily due to the construction of the Plant McIntosh combined cycle units 10 and 11 which were placed in service in June 2005.

Interest Income

Interest income decreased $4.1 million in 2006 primarily due to interest on a favorable state tax settlement of $3.8 million in 2005. Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest Expense

Interest expense increased $22.5 million, or 9.5 percent, in 2006 primarily due to generally higher interest rates on variable rate debt and commercial paper, the issuance of additional senior notes during 2005, and higher average balances on short-term debt. Interest expense increased $40.6 million, or 15.9 percent, in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Variable rates on pollution control bonds are highly correlated with the Bond Market Association Municipal Swap Index, which averaged 2.5 percent in 2005 and 1.2 percent in 2004. Variable rates on commercial paper and senior notes are highly correlated with the one-month London Interbank Offer Rate, which averaged 3.4 percent in 2005 and 1.5 percent in 2004. Interest expense remained relatively constant in 2004. The Company refinanced or retired $324 million, $635 million, and $470 million of securities in 2006, 2005, and 2004, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above.

Other Income and (Expense), net

Other income and (expense), net increased $1.9 million, or 26.7 percent, in 2006 primarily due to reduced expenses of $2.9 million and $5.0 million related to the employee stock ownership plan and charitable donations, respectively, and increased revenues of $3.6 million, $5.4 million, and $3.4 million related to a residential pricing program, customer contracting, and customer facilities charges, respectively. These increases were partially offset by net financial gains on gas hedges of $18.6 million in 2005. Other income and (expense), net increased $21.5 million in 2005 from 2004 primarily due to $16.8 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to a $15.5 million disallowance of Plant McIntosh construction costs in December 2004, 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 Regulatory Matters – Rate Plans" and "– Fuel Hedging Program" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, income tax laws are based on historical costs. 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 utility providing electricity to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for electricity relating to PPAs, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and revenues are reviewed and adjusted periodically with certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" and "FERC Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's 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 of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. 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 Company's service area. Assuming normal weather, retail sales growth is expected to be approximately 2.1 percent on average from 2007 to 2011.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

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 certain Southern Company subsidiaries, including the Company and Alabama Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities, including the Company's Plants Bowen and Scherer. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against the Company has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

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 matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. These regulatory revisions have been adopted by the State of Georgia. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City 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. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 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 requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for the Company on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, the Company had invested approximately $1.5 billion in capital projects to comply with these requirements, with annual totals of $351 million, $117 million, and $47 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $955 million, $637 million, and $316 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also significantly affect the Company. New environmental legislation or regulations, or changes to existing statutes or regulations, could affect many areas of the Company's operations; however, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $1.3 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2, NO_x, and mercury emissions, maintain compliance with existing regulations, and meet new requirements.

Approximately $700 million of the expenditures related to reducing NO_x emissions pursuant to state and federal requirements were in connection with the EPA's one-hour ozone air quality standard and the 1998 regional NO_x reduction rules.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that were designated as nonattainment under the eight-hour ozone standard include Macon and a 20-county area within metropolitan Atlanta. Macon is in the process of seeking redesignation by the EPA as an attainment area and is preparing a maintenance plan for approval. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, are currently required for Georgia by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within the Company's service area and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA is expected to publish its final rule for implementation of the existing fine particulate matter standard in early 2007. State plans for addressing the nonattainment designations under the existing standard are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. On September 21, 2006, the EPA published a final rule lowering the 24-hour fine particulate matter air quality standard even further and plans to designate nonattainment areas based on the new standard by December 2009. The final outcome of this matter cannot be determined at this time.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology- based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by the State of Georgia and therefore, cannot now be determined.

The Company is retrofitting a closed-loop recirculating cooling tower at one facility under the Clean Water Act to cool water prior to discharge and is considering undertaking similar work at an additional facility. The total estimated capital cost for this project is $96 million.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 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 Matters – Environmental Remediation" for additional information.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. Southern Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, Southern Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 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 an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $5.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power 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.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $18.8 million for the Company, of which $3.9 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC proceeding in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

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 new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, 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. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

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 "Market-Based Rate Authority" and "Generation Interconnection Agreements" above 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.

PSC Matters

Merger

Effective July 1, 2006, Savannah Electric was merged into the Company. Prior to the merger, Southern Company was the sole common shareholder of both the Company and Savannah Electric. At the time of the merger, each outstanding share of Savannah Electric common stock was cancelled and Southern Company was issued an additional 1,500,000 shares of the Company's common stock, no par value per share. In addition, at the time of the merger, each outstanding share of Savannah Electric's preferred stock was cancelled and converted into the right to receive one share of the Company's $6^1/_8$ percent Series Class A Preferred Stock, Non-Cumulative, Par Value $25 Per Share, resulting in the issuance by the Company of 1,800,000 shares of such Class A Preferred Stock in July 2006. Following completion of the merger, the outstanding capital stock of the Company consists of 9,261,500 shares of common stock, all of which are held by Southern Company, and 1,800,000 shares of Class A Preferred Stock.

With respect to the merger, the Georgia PSC voted on June 15, 2006 to set a Merger Transition Adjustment (MTA) applicable to customers in the former Savannah Electric service territory so that the fuel rate that became effective on July 1, 2006 plus the MTA equals the applicable fuel rate paid by such customers as of June 30, 2006. See "Fuel Cost Recovery" herein for additional information. Amounts collected under the MTA are being credited to customers in the original Georgia Power service territory through a Merger Transition Credit (MTC). The MTA and the MTC will be in effect until December 31, 2007, when the Company's base rates are scheduled to be adjusted.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent are applied to rate refunds, with the remaining one-third retained by the Company. Retail rates increased by approximately $194 million and customer fees increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operations and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2007, the Company will refund 2005 earnings above 12.25 percent retail ROE. No refund is anticipated for 2006.

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 Regulatory Matters – Rate Plans" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In March 2006, the Company and Savannah Electric filed a combined request for fuel cost recovery rate changes with the Georgia PSC to be effective July 1, 2006, concurrent with the merger of the companies. On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in the Company's total annual billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required the Company to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, the Company filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate. On November 13, 2006, under agreement with the Georgia PSC staff, the Company filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs.

On February 6, 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million. The order reduced the Company's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires the Company to file for a new fuel cost recovery rate no later than March 1, 2008. The new rates will become effective on March 1, 2007. Estimated under recovered fuel costs through February 2007 are to be recovered through May 2009 for customers in the original Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, the Company had an under recovered fuel balance of approximately $898 million, of which approximately $544 million is included in deferred charges and other assets in the balance sheets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. In accordance with Georgia PSC order, a portion of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets in the balance sheets. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Nuclear

On August 15, 2006, as part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear Operating Company, Inc. (SNC) filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit (ESP) on behalf of the owners of Plant Vogtle. In addition, the Company and SNC notified the NRC of their intent to apply for a combined construction and operating license (COL) in 2008. Ownership agreements have been signed with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on these co-owners. In June 2006, the Georgia PSC approved the Company's request to establish an accounting order that would allow the Company to defer for future recovery the ESP and COL costs, of which the Company's portion is estimated to total approximately $51 million over the next four years. At this point, no final decision has been made regarding actual construction. Any new generation resource must be certified by the Georgia PSC in a separate proceeding.

Other Matters

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates 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" (SFAS No. 71), 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 SFAS 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 and accounting principles generally accepted in the United States. 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 (IRS) or Georgia Department of Revenue interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, 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 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

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. As a result, compensation cost relating to share-based payment transactions must now be recognized in the Company's financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $218 million with respect to its overfunded defined benefit plan and additional liabilities and deferred credits of $13 million and $255 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007 with no material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Cash flow from operations increased $117 million in 2006, resulting primarily from increased retail operating revenues partially offset by higher fuel inventories and an increase in under recovered deferred fuel costs. In 2005, cash flow from operations increased $58 million resulting primarily from increased retail operating revenues, partially offset by the increase in under recovered deferred fuel costs. In 2004, cash flow from operations decreased $246 million resulting primarily from the increase in under recovered deferred fuel costs.

In 2006, gross property additions were $1.2 billion. These additions were primarily related to transmission and distribution facilities, 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 and the issuance of short-term debt. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization – including short-term debt – was 48.6 percent in 2006, 47.9 percent in 2005, and 47.5 percent in 2004. The Company has received investment grade ratings from the major rating agencies with respect to debt, preferred securities, and preferred stock.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approvals, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Georgia PSC, as well as the amounts, if any, 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. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. 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.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source for under recovered fuel costs and 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 credit arrangements with banks totaling $910 million, of which $904 million was unused, at the beginning of 2007. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

At the beginning of 2007, bank credit arrangements were as follows:

		Expires		
Total	Unused	2007	2008	2011
		(in millions)		
$910	$904	$40	$–	$870

The credit arrangements that expire in 2007 allow for the execution of term loans for an additional two-year period.

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 traditional 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, 2006, the Company had outstanding $733 million of commercial paper and no extendible commercial notes.

Financing Activities

During 2006, the Company issued $150 million of senior notes and incurred $154 million of obligations related to the issuance of pollution control bonds. The issuances were used to reduce the Company's short-term indebtedness and refund $154 million of higher interest rate obligations related to pollution control bonds, respectively. In addition, $20 million of first mortgage bonds matured.

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, 2006, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $7.8 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $250 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 for the Company and/or Alabama Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's exposure related to these agreements was approximately $27.4 million.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $525 million and are related to anticipated debt issuances over the next two years. Subsequent to December 31, 2006, the Company entered into hedges totaling $375 million, also related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2007 was 4.6 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 $5 million at January 1, 2007. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

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

	Changes in Fair Value	
	2006	2005
	(in millions)	
Contracts beginning of year	**$ 35.3**	$ 7.2
Contracts realized or settled	**40.2**	(46.8)
New contracts at inception	–	–
Changes in valuation techniques	–	–
Current period changes(a)	**(113.5)**	74.9
Contracts end of year	**$ (38.0)**	$ 35.3

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

Source of 2006 Year-End Valuation Prices	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in millions)		
Actively quoted	**$ (38.9)**	$ (35.9)	$ (3.0)
External sources	**0.9**	0.9	–
Models and other methods	–	–	–
Contracts end of year	**$ (38.0)**	$ (35.0)	$ (3.0)

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. Of the net financial gains, the Company was allowed to retain 25 percent in earnings through June 30, 2006. In 2005, the Company had a total net gain of $74.6 million of which the Company retained $18.6 million. There were no net financial gains in 2006 and 2004. Effective July 1, 2006, the Georgia PSC ordered the suspension of the profit sharing framework related to the fuel hedging program. New profit sharing arrangements as well as other charges to the fuel hedging program are currently under development. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	$ (38.0)
Net income	–
Total fair value	$ (38.0)

Unrealized gains (losses) recognized in income in 2006, 2005, and 2004 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 $1.9 billion for 2007, $1.8 billion for 2008, and $1.8 billion for 2009. Environmental expenditures included in these amounts are $955 million, $637 million, and $316 million for 2007, 2008, and 2009, respectively. Actual construction costs may vary from these estimates because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and 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.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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, derivatives, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[a] --					
Principal	$ 304	$ 328	$ 119	$ 4,768	$ 5,519
Interest	285	537	506	5,411	6,739
Preferred stock dividends[b]	3	6	6	–	15
Derivative obligations[c]	42	4	–	–	46
Operating leases	32	55	44	42	173
Purchase commitments[d] --					
Capital[e]	1,829	3,437	–	–	5,266
Coal	1,638	2,446	392	44	4,520
Nuclear fuel	94	161	222	169	646
Natural gas[f]	647	876	464	1,914	3,901
Purchased power	355	724	479	1,255	2,813
Long-term service agreements	12	26	34	139	211
Trusts --					
Nuclear decommissioning[g]	7	14	14	110	145
Postretirement benefits[h]	16	43	–	–	59
Total	$ 5,264	$ 8,657	$ 2,280	$ 13,852	$ 30,053

(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, 2007, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

(c) For additional information see Notes 1 and 6 to the financial statements.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.6 billion, $1.6 billion, and $1.5 billion, respectively.

(e) The Company forecasts capital expenditures over a three-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, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan.

(h) 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 and postretirement 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 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, fuel cost recovery, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the impacts of the adoption of new accounting rules, 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, implementation of the Energy Policy Act of 2005, 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 FERC matters and 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, including rate cases related to fuel cost recovery;
- 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, pandemic health events such as an avian influenza, 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 (including the Form 10-K) filed by the Company 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, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 6,205,620**	$ 6,064,363	$ 5,118,751
Sales for resale --			
Non-affiliates	**551,731**	524,800	251,581
Affiliates	**252,556**	275,525	172,375
Other revenues	**235,737**	211,149	185,061
Total operating revenues	**7,245,644**	7,075,837	5,727,768
Operating Expenses:			
Fuel	**2,233,029**	1,937,378	1,288,491
Purchased power --			
Non-affiliates	**332,606**	421,033	316,390
Affiliates	**812,433**	895,243	785,359
Other operations	**1,025,848**	1,009,993	962,390
Maintenance	**534,621**	561,464	522,945
Depreciation and amortization	**498,754**	526,652	296,740
Taxes other than income taxes	**298,824**	276,027	243,051
Total operating expenses	**5,736,115**	5,627,790	4,415,366
Operating Income	**1,509,529**	1,448,047	1,312,402
Other Income and (Expense):			
Allowance for equity funds used during construction	**31,524**	29,145	29,038
Interest income	**2,459**	6,537	6,865
Interest expense, net of amounts capitalized	**(258,437)**	(235,976)	(194,415)
Interest expense to affiliate trusts	**(59,510)**	(59,510)	(44,565)
Distributions on mandatorily redeemable preferred securities	**–**	–	(15,948)
Other income (expense), net	**8,833**	6,971	(14,512)
Total other income and (expense)	**(275,131)**	(252,833)	(233,537)
Earnings Before Income Taxes	**1,234,398**	1,195,214	1,078,865
Income taxes	**442,334**	447,448	393,902
Net Income	**792,064**	747,766	684,963
Dividends on Preferred Stock	**4,839**	3,393	2,170
Net Income After Dividends on Preferred Stock	**$ 787,225**	$ 744,373	$ 682,793

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	$ 792,064	$ 747,766	$ 684,963
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	588,428	616,963	385,668
Deferred income taxes and investment tax credits, net	16,159	257,501	265,064
Deferred expenses -- affiliates	1,558	1,268	(10,563)
Allowance for equity funds used during construction	(31,524)	(29,145)	(29,038)
Pension, postretirement, and other employee benefits	18,604	(13,335)	(11,002)
Stock option expense	5,805	–	–
Tax benefit of stock options	1,163	17,263	10,562
Other, net	1,735	(8,201)	(27,519)
Changes in certain current assets and liabilities --			
Receivables	1,193	(650,593)	(258,737)
Fossil fuel stock	(194,256)	(2,898)	(48,668)
Materials and supplies	31,317	(55,805)	(224)
Prepaid income taxes	1,060	(38,975)	10,624
Other current assets	774	3,585	(25,263)
Accounts payable	(85,189)	122,117	142,136
Accrued taxes	82,735	77,164	(60,859)
Accrued compensation	(10,328)	4,162	(6,704)
Other current liabilities	(21,054)	34,029	4,012
Net cash provided from operating activities	1,200,244	1,082,866	1,024,452
Investing Activities:			
Property additions	(1,219,498)	(891,314)	(788,828)
Nuclear decommissioning trust fund purchases	(464,274)	(381,235)	(541,048)
Nuclear decommissioning trust fund sales	457,394	372,536	532,349
Purchase of property from affiliates	–	–	(414,582)
Cost of removal net of salvage	(33,620)	(30,764)	(22,642)
Change in construction payables, net of joint owner portion	35,075	4,190	1,978
Other	(16,005)	(788)	(5,101)
Net cash used for investing activities	(1,240,928)	(927,375)	(1,237,874)
Financing Activities:			
Increase in notes payable, net	406,768	97,713	91,523
Proceeds --			
Senior notes	150,000	625,000	635,000
Preferred stock	–	–	45,000
Pollution control bonds	153,910	185,000	–
Gross excess tax benefit of stock options	2,796	–	–
Mandatorily redeemable preferred securities	–	–	200,000
Capital contributions from parent company	312,544	149,475	307,323
Other long term debt	–	–	10,000
Redemptions --			
Pollution control bonds	(153,910)	(185,000)	–
Capital leases	(136)	(1,095)	(1,014)
Senior notes	(150,000)	(450,000)	(200,000)
First mortgage bonds	(20,000)	–	–
Preferred stock	(14,569)	–	–
Mandatorily redeemable preferred securities	–	–	(240,000)
Other long term debt	–	–	(30,000)
Payment of preferred stock dividends	(2,958)	(3,246)	(1,479)
Payment of common stock dividends	(630,000)	(582,800)	(588,700)
Other	(8,049)	(21,760)	(18,514)
Net cash provided from (used for) financing activities	46,396	(186,713)	209,139
Net Change in Cash and Cash Equivalents	5,712	(31,222)	(4,283)
Cash and Cash Equivalents at Beginning of Year	11,138	42,360	46,643
Cash and Cash Equivalents at End of Year	$ 16,850	$ 11,138	$ 42,360
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $12,530, $11,949, and $10,392 capitalized, respectively)	$ 317,536	$ 263,802	$ 238,270
Income taxes (net of refunds)	398,735	196,930	131,696

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

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BALANCE SHEETS

At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 16,850	$ 11,138
Receivables --		
Customer accounts receivable	474,046	447,270
Unbilled revenues	130,585	148,526
Under recovered regulatory clause revenues	353,976	483,673
Other accounts and notes receivable	93,656	112,452
Affiliated companies	21,941	81,474
Accumulated provision for uncollectible accounts	(10,030)	(9,563)
Fossil fuel stock, at average cost	392,011	197,754
Vacation pay	61,907	59,190
Materials and supplies, at average cost	304,514	335,684
Prepaid expenses	74,788	73,216
Other	72,041	59,373
Total current assets	1,986,285	2,000,187
Property, Plant, and Equipment:		
In service	21,279,792	20,636,505
Less accumulated provision for depreciation	8,343,309	7,972,913
	12,936,483	12,663,592
Nuclear fuel, at amortized cost	180,129	134,798
Construction work in progress	923,948	584,470
Total property, plant, and equipment	14,040,560	13,382,860
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	70,879	70,664
Nuclear decommissioning trusts, at fair value	544,013	486,591
Other	58,848	73,271
Total other property and investments	673,740	630,526
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	510,531	512,337
Prepaid pension costs	688,671	455,514
Deferred under recovered regulatory clause revenues	544,152	343,804
Other regulatory assets	629,003	340,938
Other	235,788	232,279
Total deferred charges and other assets	2,608,145	1,884,872
Total Assets	$ 19,308,730	$ 17,898,445

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

BALANCE SHEETS

At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ **303,906**	$ 188,319
Notes payable	**733,281**	326,513
Accounts payable --		
Affiliated	**238,093**	305,754
Other	**402,222**	379,810
Customer deposits	**155,763**	136,360
Accrued taxes --		
Income taxes	**217,603**	128,560
Other	**275,098**	206,687
Accrued interest	**74,643**	92,109
Accrued vacation pay	**49,704**	48,388
Accrued compensation	**141,356**	143,255
Other	**125,494**	132,547
Total current liabilities	**2,717,163**	2,088,302
Long-term Debt (See accompanying statements)	**4,242,839**	4,396,250
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	**969,073**	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,815,724**	2,849,727
Deferred credits related to income taxes	**157,297**	166,736
Accumulated deferred investment tax credits	**282,070**	295,024
Employee benefit obligations	**698,274**	391,854
Asset retirement obligations	**626,681**	634,932
Other cost of removal obligations	**436,137**	445,189
Other regulatory liabilities	**281,391**	99,385
Other	**80,839**	65,981
Total deferred credits and other liabilities	**5,378,413**	4,948,828
Total Liabilities	**13,307,488**	12,402,453
Preferred Stock (See accompanying statements)	**44,991**	43,909
Common Stockholder's Equity (See accompanying statements)	**5,956,251**	5,452,083
Total Liabilities and Stockholder's Equity	$ **19,308,730**	$ 17,898,445
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
First mortgage bonds -- 6.9% due May 1, 2006	$ –	$ 20,000		
Long-term notes payable --				
6.20% due February 1, 2006	–	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
6.55% due May 15, 2008	**45,000**	45,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (5.54% at 1/1/07) due 2009	**150,000**	150,000		
4.00% due 2011	**100,000**	100,000		
4.90% to 6.00% due 2012-2045	**2,050,000**	1,900,000		
Total long-term notes payable	**2,770,000**	2,770,000		
Other long-term debt --				
Pollution control revenue bonds:				
2.83% to 5.45% due 2012-2036	**774,370**	812,560		
Variable rate (3.50% to 4.05% at 1/1/07) due 2011-2041	**929,475**	891,285		
Total other long-term debt	**1,703,845**	1,703,845		
Capitalized lease obligations	**76,227**	79,564		
Unamortized debt premium (discount), net	**(3,327)**	(3,449)		
Total long-term debt (annual interest requirement -- $225.7 million)	**4,546,745**	4,569,960		
Less amount due within one year	**303,906**	173,710		
Long-term debt excluding amount due within one year	**4,242,839**	4,396,250	**37.9%**	40.5%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042-2044 (annual interest requirement -- $59.5 million)	**969,073**	969,073	**8.6**	8.9
Preferred Stock:				
Cumulative preferred stock				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 2006: 0 shares				
-- 2005: 145,689 shares	–	14,609		
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized -- 50,000,000 shares				
Outstanding -- 1,800,000 shares	**44,991**	43,909		
(annual dividend requirement -- $2.8 million)				
Total preferred stock	**44,991**	58,518		
Less amount due within one year	—	14,609		
Total preferred stock excluding amount due within one year	**44,991**	43,909	**0.4**	0.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398,473**	398,473		
Paid-in capital	**3,039,845**	2,717,539		
Retained earnings	**2,529,826**	2,372,637		
Accumulated other comprehensive income (loss)	**(11,893)**	(36,566)		
Total common stockholder's equity	**5,956,251**	5,452,083	**53.1**	50.2
Total Capitalization	**$ 11,213,154**	$ 10,861,315	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$ 398,473	$ 2,232,956	$ 2,116,949	$ (25,079)	$ 4,723,299
Net income after dividends on preferred stock	–	–	682,793	–	682,793
Capital contributions from parent company	–	317,885	–	–	317,885
Other comprehensive income (loss)	–	–	–	(11,961)	(11,961)
Cash dividends on common stock	–	–	(588,700)	–	(588,700)
Other	–	(40)	–	–	(40)
Balance at December 31, 2004	**398,473**	**2,550,801**	**2,211,042**	**(37,040)**	**5,123,276**
Net income after dividends on preferred stock	–	–	744,373	–	744,373
Capital contributions from parent company	–	166,738	–	–	166,738
Other comprehensive income (loss)	–	–	–	474	474
Cash dividends on common stock	–	–	(582,800)	–	(582,800)
Other	–	–	22	–	22
Balance at December 31, 2005	**398,473**	**2,717,539**	**2,372,637**	**(36,566)**	**5,452,083**
Net income after dividends on preferred stock	–	–	**787,225**	–	**787,225**
Capital contributions from parent company	–	**322,306**	–	–	**322,306**
Other comprehensive income (loss)	–	–	–	**5,184**	**5,184**
Adjustment to initially apply FASB Statement No. 158, net of tax	–	–	–	**19,489**	**19,489**
Cash dividends on common stock	–	–	**(630,000)**	–	**(630,000)**
Other	–	–	**(36)**	–	**(36)**
Balance at December 31, 2006	**$ 398,473**	**$ 3,039,845**	**$ 2,529,826**	**$ (11,893)**	**$ 5,956,251**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred stock	**$ 787,225**	$ 744,373	$ 682,793
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $5,143, $(2,216) and $(4,115), respectively	**8,155**	(3,512)	(6,523)
Change in fair value of marketable securities, net of tax of $(494), $317 and $(114), respectively	**(817)**	501	(181)
Changes in fair value of qualifying hedges, net of tax of $(935), $1,522 and $(4,885), respectively	**(1,454)**	2,420	(7,744)
Less: Reclassification adjustment for amounts included in net income, net of tax of $(441), $861 and $1,568, respectively	**(700)**	1,065	2,487
Total other comprehensive income (loss)	**5,184**	474	(11,961)
Comprehensive Income	**$ 792,409**	$ 744,847	$ 670,832

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

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2006 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, the Company, Gulf Power, and Mississippi Power – provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company 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. On January 4, 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

Effective July 1, 2006, the Company merged with Savannah Electric. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements now reflect the merger as though it had occurred on January 1, 2004. See Note 3 under "Retail Regulatory Matters – Merger" for additional information.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform with the current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (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.

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 $386 million in 2006, $348 million in 2005, and $310 million in 2004. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

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, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $348 million in 2006, $328 million in 2005, and $311 million in 2004.

The Company has an agreement with Southern Power under which the Company operates and maintains Southern Power owned Plants Dahlberg, Franklin, and Wansley at cost. Billings under these agreements with Southern Power amounted to $5.4 million in 2006, $5.2 million in 2005, and $4.8 million in 2004.

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 $7.1 million in 2006, $7.7 million in 2005, and $8.0 million in 2004.

Southern Company's 30 percent ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel, was terminated July 1, 2006. 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 $76 million in 2006, $61 million in 2005, and $53 million in 2004. In addition, the Company purchases synthetic fuel from AFP for use at Plant Branch. Fuel purchases totaled $146 million through June 30, 2006, $216 million in 2005, and $163 million in 2004.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $407 million, $469 million, and $314 million in 2006, 2005, and 2004, respectively. Additionally, the Company had $28 million and $29 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2006 and 2005, 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 $8.0 million in 2006, $4.3 million in 2005, and $6.8 million in 2004. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in 2005, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.3 million, $5.0 million, and $55.2 million, respectively. These activities were billed at cost.

Also see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

The traditional operating companies, including the Company, and Southern Power 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.

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" (SFAS No. 71). 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:

	2006	2005	Note
	(in millions)		
Deferred income tax charges	$ 511	$ 513	(a)
Premium on reacquired debt	171	177	(b)
Vacation pay	62	59	(c)
Corporate building lease	51	52	(d)
Postretirement benefits	15	18	(d)
Generating plant outage costs	56	53	(e)
Underfunded retiree benefit plans	310	-	(f)
Fuel-hedging assets	58	12	(g)
Other regulatory assets	27	30	(d)
Asset retirement obligations	53	71	(a)
Other cost of removal obligations	(436)	(445)	(a)
Deferred income tax credits	(157)	(167)	(a)
Environmental remediation	(16)	(19)	(h)
Purchased power	(19)	(33)	(h)
Overfunded retiree benefit plans	(218)	-	(f)
Fuel-hedging liabilities	(6)	(47)	(g)
Other regulatory liabilities	(4)	(4)	(d)
Total	$ 458	$ 270	

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

(d) Recorded and recovered or amortized as approved by the Georgia PSC.

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

(f) Recovered and amortized over the average remaining service period which may range up to 17 years. See Note 2 under "Retirement Benefits."

(g) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed 42 months. Upon final settlement, costs are recovered through the fuel cost recovery clauses.

(h) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters – Rate Plans."

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 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, write down the assets, if impaired, to their fair value. All regulatory assets and liabilities are reflected in rates.

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 and the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

Retail fuel cost recovery rates require periodic filings with the Georgia PSC. The Company is required to file its next fuel case by March 1, 2008. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery."

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.

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 $71 million in 2006, $70 million in 2005, and $73 million in 2004.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 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 2014. 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 is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Also, the Energy Policy Act of 1992 established a Uranium Enrichment Decontamination and Decommissioning Fund, which has been funded in part by a special assessment on utilities with nuclear plants. This assessment was paid over a 15-year period; the final installment occurred in 2006. 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.

State 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. State tax credits of $19.9 million, $9.4 million, and $13.1 million were recorded in 2006, 2005, and 2004, respectively.

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 Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2006	2005
Generation	**$ 10,064**	$ 9,988
Transmission	**3,331**	3,144
Distribution	**6,652**	6,365
General	**1,205**	1,111
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 21,280**	$ 20,636

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. Also, in accordance with the Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Income and Other 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. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in each of 2006, 2005, and 2004. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2005, the Company's depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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 Company's retail rate plan for the three years ending December 31, 2007 (2004 Retail Rate Plan), the Company was ordered to recognize Georgia PSC – certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. The Company recorded a credit to amortization of $14 million in 2006 as well as $33 million in 2005. Under the retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Georgia PSC ordered the Company to amortize $333 million, the cumulative balance of accelerated depreciation and amortization previously expensed, equally over three years as a credit to depreciation and amortization expense beginning January 2002. The Company also was ordered to recognize new certified capacity costs in rates evenly over the same three-year period under the 2001 Retail Rate Plan. As a result, the Company recorded a reduction in depreciation and amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters – Rate Plans" 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" (SFAS No. 143), which 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. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

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, 2006 was $544 million. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of approximately $95 million related to asbestos removal. The Company also has 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 assets 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. 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:

	2006	2005
	(in millions)	
Balance beginning of year	**$ 635**	$ 510
Liabilities incurred	**5**	95
Liabilities settled	**(2)**	(3)
Accretion	**41**	33
Cash flow revisions	**(52)**	–
Balance end of year	**$ 627**	$ 635

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 external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. As the external trust funds are actively managed by unrelated parties with limited direction from the Company, the Company does not have the ability to choose to hold securities with unrealized losses until recovery. Through 2005, the Company considered other-than-temporary impairments to be immaterial. However, since the January 1, 2006 effective date of FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" (FSP No. 115-1), the Company considers all unrealized losses to represent other-than-temporary impairments. The adoption of FSP No. 115-1 had no impact on the results of operations, cash flows, or financial condition of the Company as all losses have been and continue to be recorded through a regulatory liability, whether realized, unrealized, or identified as other-than-temporary. Details of the securities held in these trusts at December 31 are as follows:

2006	Unrealized Gains	Other-than-Temporary Impairments	Fair Value
		(in millions)	
Equity	**$ 106.9**	**$ (5.0)**	**$ 378.3**
Debt	**3.0**	**(0.7)**	**165.4**
Other	**–**	**–**	**0.3**
Total	**$ 109.9**	**$ (5.7)**	**$ 544.0**

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$ 76.7	$ (6.3)	$ 325.5
Debt	2.8	(0.8)	135.3
Other	–	–	25.8
Total	$ 79.5	$ (7.1)	$ 486.6

The contractual maturities of debt securities at December 31, 2006 are as follows: $6.8 million in 2007, $41.0 million in 2008-2011, $42.0 million in 2012-2016, and $75.3 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $457.4 million, $372.5 million, and $532.3 million in 2006, 2005, and 2004, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were $17.8 million and $12.1 million, respectively, in 2006. Net realized gains/(losses) were $12.6 million and $14.1 million in 2005 and 2004, respectively. Realized gains and other-than-temporary impairment losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and other-than-temporary impairment losses are considered non-cash transactions for purposes of the statements of cash flows. Unrealized losses were not material in any period presented and did not require the recognition of any impairment to the underlying investments.

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. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2006 and the accumulated provisions for decommissioning at December 31, 2006 were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2006	$ –	$ 6
Accumulated provisions:		
External trust funds, at fair value	$ 344	$ 200
Internal reserves	–	1
Total	$ 344	$ 201

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2006, which will be filed with the Georgia PSC in 2007 as a part of the retail base rate case. The Company's ownership interests in Plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2061	2051
	(in millions)	
Site study costs:		
Radiated structures	$ 544	$ 507
Non-radiated structures	46	67
Total	$ 590	$ 574

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.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking 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 plans to file an application with the NRC in June 2007 to extend the licenses for Plant Vogtle units 1 and 2 for an additional 20 years. 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, which 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 2006, 2005, and 2004, the average AFUDC rates were 8.3 percent, 8.0 percent, and 8.0 percent, respectively, and AFUDC capitalized was $44.1 million, $41.1 million, and $39.1 million, respectively. AFUDC and interest capitalized, net of taxes, were 5.0 percent, 4.9 percent, and 5.2 percent of net income after dividends on preferred stock for 2006, 2005, and 2004 respectively.

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 loss 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 Regulatory Matters – Rate Plans" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

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. The Company accrues $6.6 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Cost Recovery

The Company continues to recover environmental costs through its base rates. Beginning in 2005, such rates include an annual accrual of $5.4 million for environmental remediation. 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 Georgia PSC ratemaking provisions, $22 million had previously been deferred in a regulatory liability account for use in meeting future environmental remediation costs of the Company and is being amortized over a three-year period that began in January 2005.

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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. Prior to January 1, 2006, the Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as of January 1, 2006, for which the requisite service had not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

For the Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings before income taxes and net income of $6 million and $4 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $3 million.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact of fair-value accounting for options granted on net income is as follows:

Net Income	As Reported	Options Impact After Tax	Pro Forma
	(in millions)		
2005	$ 744	$ (3)	$ 741
2004	$ 683	$ (4)	$ 679

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	**2006**	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant-date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

The Company uses derivative financial instruments to limit exposure 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. 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 or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges 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:		
2006	**$ 5,440**	**$ 5,376**
2005	$ 5,460	$ 5,427

The fair values were based on either closing market price or closing price of comparable instruments.

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not considered 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 in the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $16 million.

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, the Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to each of its underfunded non-qualified pension plans, the Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

Upon the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life. SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statement of income. Upon the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $218 million with respect to its overfunded defined benefit plan and additional liabilities and deferred credits of $13 million and $255 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. The incremental effect of applying SFAS No. 158 on individual line items in the balance sheet at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension costs	$ 471	$ 218	$ 689
Other regulatory assets	319	310	629
Other property and investments	685	(11)	674
Total assets	18,792	517	19,309
Accumulated deferred income taxes	(2,803)	(13)	(2,816)
Other regulatory liabilities	(63)	(218)	(281)
Employee benefit obligations	(431)	(267)	(698)
Total liabilities	(12,810)	(498)	(13,308)
Accumulated other comprehensive income	31	(19)	12
Total stockholders' equity	(5,982)	(19)	(6,001)

Because of pension and postretirement benefit expenses are components of the Company's regulated rates, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, the Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.0 billion in 2006 and $2.0 billion in 2005. Changes during the year in the projected benefit obligations and the fair value of plan assets were as follows:

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,172**	$ 1,989
Service cost	**53**	47
Interest cost	**117**	112
Benefits paid	**(95)**	(90)
Plan amendments	**2**	13
Actuarial (gain) loss	**(113)**	101
Balance at end of year	**2,136**	2,172
Change in plan assets		
Fair value of plan assets at beginning of year	**2,493**	2,229
Actual return on plan assets	**308**	346
Employer contributions	**6**	8
Benefits paid	**(95)**	(90)
Employee transfers	**(2)**	–
Fair Value of plan assets at end of year	**2,710**	2,493
Funded status at end of year	**574**	321
Unrecognized transition amounts	**–**	(4)
Unrecognized prior service cost	**–**	116
Unrecognized net (gain) loss	**–**	(27)
Fourth quarter contributions	**2**	2
Prepaid pension asset, net	**$ 576**	$ 408

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $2.0 billion and $0.1 billion, respectively. All plan assets are related to the qualified plan.

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. 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. The actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	**38%**	40%
International equity	24	**23**	24
Fixed income	15	**16**	17
Real estate	15	**16**	13
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of the following:

	2006	2005
	(in millions)	
Prepaid pension costs	**$ 689**	$ 456
Other regulatory assets	**56**	–
Current liabilities, other	**(6)**	–
Other regulatory liabilities	**(218)**	–
Employee benefit obligations	**(107)**	(109)
Other property and investments	**–**	17
Accumulated other comprehensive income	**–**	45

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year:

	Prior Service Cost	Net (Gain)/ Loss
Balance at December 31, 2006:	(in millions)	
Regulatory asset	**$ 11**	$ 45
Regulatory liabilities	**92**	(310)
Total	**$ 103**	$ (265)
Estimated amortization in net periodic pension cost in 2007:		
Regulatory assets	**$ 2**	$ 3
Regulatory liabilities	**11**	–
Total	**$ 13**	$ 3

Components of net periodic pension cost (income) and other amounts recognized in other comprehensive income were as follows:

	2006	2005	2004
	(in millions)		
Service cost	**$ 53**	$ 47	$ 44
Interest cost	**117**	112	106
Expected return on plan assets	**(184)**	(186)	(184)
Recognized net (gain)/loss	**6**	4	(4)
Net amortization	**8**	9	8
Net pension (income)	**$ –**	$ (14)	$ (30)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

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, 2006, estimated benefit payments were as follows:

	(in millions)
2007	$ 101
2008	105
2009	110
2010	115
2011	121
2012 to 2016	713

Other Postretirement Benefits

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

	2006	2005
	(in millions)	
Change in benefit obligation		
Balance at beginning of year	$ 812	$ 765
Service cost	11	11
Interest cost	43	43
Benefits paid	(34)	(33)
Actuarial gain (loss)	(27)	26
Retiree drug subsidy	2	–
Balance at end of year	807	812
Change in plan assets		
Fair value of plan assets at beginning of year	362	312
Actual return on plan assets	35	40
Employer contributions	48	43
Benefits paid	(57)	(33)
Fair value of plan assets at end of year	388	362
Funded status at end of year	(419)	(450)
Unrecognized transition amount	–	73
Unrecognized prior service cost	–	26
Unrecognized net (gain) loss	–	215
Fourth quarter contributions	20	23
Accrued liability (recognized in the balance sheet)	$ (399)	$ (113)

Other 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. 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. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	42%	44%	46%
International equity	19	20	18
Fixed income	29	27	29
Real estate	6	6	5
Private equity	4	3	2
Total	100%	100%	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2006	2005
	(in millions)	
Other regulatory assets	$ 255	$ –
Employee benefit obligations	(399)	(113)

Presented below are the amounts included in regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost:

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2006			
Regulatory assets	$ 24	$ 166	$ 64
Estimated amortization in net periodic postretirement benefit cost in 2007:			
Regulatory assets	$ 2	$ 8	$ 9

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

	2006	2005	2004
		(in millions)	
Service cost	$ 11	$ 11	$ 11
Interest cost	44	43	43
Expected return on plan assets	(25)	(23)	(26)
Net amortization	22	19	19
Net postretirement cost	$ 52	$ 50	$ 47

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2), 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 APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced the Company's expenses for the year ended December 31, 2006, the year ended December 31, 2005, and the six months ended December 31, 2004 by approximately $16 million, $11 million, and $5 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO 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)		
2007	$ 37	$ 3	$ 34
2008	41	3	38
2009	45	4	41
2010	48	4	44
2011	52	5	47
2012 to 2016	296	33	263

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
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 APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 67	$ 57
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 an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $21 million, $20 million, and $19 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 such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, 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.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities, including the Company's Plants Bowen and Scherer. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after it was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty, and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization, and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit, and on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against the Company has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

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. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 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 requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for the Company on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

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. 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. As of December 31, 2006, the Company had recorded approximately $6 million in cumulative expenses associated with its agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2006 for the assessment and anticipated cleanup of other sites on the Georgia Hazardous Sites Inventory.

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 activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 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 an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $5.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power 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.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $18.8 million for the Company, of which $3.9 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

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 new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, 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. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC.

On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. 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. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 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 court also dismissed Southern Telecom from this case. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the trial court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which was also denied. On October 10, 2006, the Superior Court of Decatur County, Georgia granted the Company's motion for summary judgment. The period during which the plaintiff could have appealed has expired. This matter is now concluded.

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. In January 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.

Property Tax Dispute

The Company is involved in a property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2006 of up to $18 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

Effective July 1, 2006, Savannah Electric was merged into the Company. Prior to the merger, Southern Company was the sole common shareholder of both the Company and Savannah Electric. At the time of the merger, each outstanding share of Savannah Electric common stock was cancelled and Southern Company was issued an additional 1,500,000 shares of the Company's common stock, no par value per share. In addition, at the time of the merger, each outstanding share of Savannah Electric's preferred stock was cancelled and converted into the right to receive one share of the Company's $6^1/_8$ percent Series Class A Preferred Stock, Non-Cumulative, Par Value $25 Per Share, resulting in the issuance by the Company of 1,800,000 shares of such Class A Preferred Stock in July 2006. The exchange of preferred stock was a non-cash transaction for purposes of the statements of cash flows. Following completion of the merger, the outstanding capital stock of the Company consists of 9,261,500 shares of common stock, all of which are held by Southern Company, and 1,800,000 shares of Class A Preferred Stock.

With respect to the merger, the Georgia PSC voted on June 15, 2006 to set a Merger Transition Adjustment (MTA) applicable to customers in the former Savannah Electric service territory so that the fuel rate that became effective on July 1, 2006 plus the MTA equals the applicable fuel rate paid by such customers as of June 30, 2006. See "Fuel Cost Recovery" below for additional information. Amounts collected under the MTA are being credited to customers in the original Georgia Power service territory through a Merger Transition Credit (MTC). The MTA and the MTC will be in effect until December 31, 2007, when the Company's base rates are scheduled to be adjusted.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the Company. Under the terms of the 2004 Retail Rate Plan, the Company's earnings are evaluated against a retail return on equity (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 and customer fees increased by approximately $203 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 2007, the Company will refund 2005 earnings above 12.25 percent retail ROE. No refunds are anticipated for 2006.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project from Southern Power at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance and reduced the Company's net income by approximately $9.5 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending December 31, 2007.

In May 2005, the Georgia PSC approved a new three-year rate plan for the former Savannah Electric ending May 31, 2008. Under the terms of the plan, earnings were evaluated against a retail ROE range of 9.75 percent to 11.75 percent. Retail base revenues increased in June 2005 by approximately $9.6 million.

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. In connection with this case, the former Savannah Electric's base rate tariffs will be combined with the Company's.

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. The Company's earnings in all three years were within the common equity range. Under the 2001 Retail Rate Plan, the Company amortized a regulatory liability of $333 million, related to previously recorded accelerated amortization expenses, equally over three years beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to certified purchase power contracts evenly into rates over a three-year period ended December 31, 2004.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In March 2006, the Company and Savannah Electric filed a combined request for fuel cost recovery rate changes with the Georgia PSC to be effective July 1, 2006, concurrent with the merger of the companies. On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in the Company's total annual fuel billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required the Company to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, the Company filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate. On November 13, 2006, under agreement with the Georgia PSC staff, the Company filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs.

On February 6, 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million. The Georgia PSC order reduced the Company's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires the Company to file for a new fuel cost recovery rate no later than March 1, 2008. Estimated under recovered fuel costs through February 2007 are to be recovered through May 2009 for customers in the original Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, the Company had an under recovered fuel balance of approximately $898 million, of which approximately $544 million is included in deferred charges and other assets in the balance sheets.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005.

In November 2005, the Georgia PSC voted to approve Savannah Electric's request to increase customer rates to recover estimated under recovered fuel cost of approximately $71.8 million as of November 30, 2005 over an estimated four-year period beginning December 1, 2005, as well as future projected fuel costs.

Fuel Hedging Program

In 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, through June 30, 2006, were shared with the retail customers receiving 75 percent and the Company retaining 25 percent of the total net gains. Effective July 1, 2006, the Georgia PSC ordered the suspension of the profit sharing framework related to the fuel hedging program. New profit sharing arrangements as well as other changes to the fuel hedging program are currently under development. In 2005, the Company had a total net gain of $74.6 million, of which the Company retained $18.6 million. The Company had no net gains in 2004 or 2006.

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:

	2006	2005	2004
	(in millions)		
Energy	$ 58	$ 54	$ 51
Capacity	38	38	36
Total	$ 96	$ 92	$ 87

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 has contracted to operate and maintain the plants as agent for the co-owners and 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 and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2006, 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%	$ 3,289	$ 1,857
Plant Hatch (nuclear)	50.1	925	502
Plant Wansley (coal)	53.5	396	179
Plant Scherer (coal)			
Units 1 and 2	8.4	116	60
Unit 3	75.0	565	291
Rocky Mountain (pumped storage)	25.4	170	95
Intercession City (combustion-turbine)	33.3	12	2

At December 31, 2006, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $53.1 million, $8.7 million, and $1.6 million, respectively, primarily for environmental projects.

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 files a consolidated federal income tax return and combined income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, 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 income 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 $9.2 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2006.

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 remaining balance of the related deferred taxes of $5.0 million reflected in Southern Power's future taxable income. $4.5 million of this payable to Southern Power is included in Other Deferred Credits and $0.5 million is included in Affiliated Accounts Payable in the balance sheets at December 31, 2006.

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 $10.0 million reflected in the Company's future taxable income. $8.7 million of this receivable from Southern Power is included in Other Deferred Debits and $1.3 million is included in Affiliated Accounts Receivable in the balance sheets at December 31, 2006.

At December 31, 2006, tax-related regulatory assets were $511 million and tax-related regulatory liabilities were $157 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:

	2006	2005	2004
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$ 393**	$166	$ 116
Deferred	**7**	226	233
	400	392	349
State:			
Current	**33**	24	13
Deferred	**9**	32	31
Deferred investment tax credits	**–**	–	–
Total	**$ 442**	$448	$ 393

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:

	2006	2005
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$ 2,303**	$ 2,281
Property basis differences	**568**	558
Employee benefit obligations	**243**	163
Fuel clause under recovery	**365**	335
Premium on reacquired debt	**69**	72
Underfunded benefit plans	**156**	–
Asset retirement obligations	**242**	246
Other	**75**	87
Total	**4,021**	3,742
Deferred tax assets:		
Federal effect of state deferred taxes	**123**	119
Other property basis differences	**138**	139
Other deferred costs	**131**	126
Employee benefit obligations	**226**	73
Other comprehensive income	**9**	25
Overfunded benefit plans	**84**	–
Unbilled revenue	**27**	15
Asset retirement obligations	**242**	246
Other	**41**	40
Total	**1,021**	783
Total deferred tax liabilities, net	**3,000**	2,959
Portion included in current (liabilities) assets, net	**(185)**	(110)
Accumulated deferred income taxes in the balance sheets	**$ 2,815**	$ 2,849

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 $13.0 million in 2006, 2005, and 2004. At December 31, 2006, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	3.1	2.6
Non-deductible book depreciation	**1.1**	1.2	1.2
Other	**(2.5)**	(1.8)	(2.3)
Effective income tax rate	**35.8%**	37.5%	36.5%

In 2006, the Company filed its 2005 income tax returns, which included certain state income tax credits that resulted in a lower effective income tax rate for the year ended December 31, 2006 when compared to 2005. The Company has also filed similar claims for the years 2001 through 2004. Amounts recorded in the Company's financial statements for the year ended December 31, 2006 related to these claims are not material. The Georgia Department of Revenue is currently reviewing these claims. If approved as filed, such claims could have a significant, and possibly material, effect on the Company's net income. The ultimate outcome of this matter cannot now be determined.

6. FINANCING

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or preference stock were outstanding at December 31, 2006. The outstanding Class A preferred stock is subject to redemption at the option of the Company on or after July 1, 2009.

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 these 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, 2006, 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.

Securities Due Within One Year

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

	2006	2005
	(in millions)	
Capital lease	$ 4	$ 3
Senior notes	300	150
Preferred stock	–	15
First mortgage bonds	–	20
Total	$ 304	$ 188

Redemptions and/or maturities through 2011 applicable to total long-term debt are as follows: $304 million in 2007; $49 million in 2008; $279 million in 2009; $5 million in 2010; and $115 million in 2011.

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, 2006 was $1.7 billion.

Senior Notes

The Company issued $150 million aggregate principal amount of unsecured senior notes in 2006. The proceeds of the issuance were used to repay a portion of the Company's short term indebtedness. At December 31, 2006 and 2005, the Company had $2.8 billion and $2.8 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company.

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, 2006 and 2005, the Company had a capitalized lease obligation for its corporate headquarters building of $72 million and $74 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. See Note 1 under "Regulatory Assets and Liabilities." At December 31, 2006 and 2005, the Company had capitalized lease obligations for its Plant Kraft coal unloading dock and its vehicles of $4.1 million and $5.1 million, respectively. However, for ratemaking purposes, these obligations are treated as operating leases and, as such, lease payments are charged to expense as incurred. The annual expense incurred for these leases in 2006, 2005, and 2004 was $9.6 million, $9.7 million, and $9.6 million, respectively.

Bank Credit Arrangements

At the beginning of 2007, the Company had credit arrangements with banks totaling $910 million, of which $904 million was unused. Of these facilities, $40 million expires during 2007, with the remaining $870 million expiring in 2011. The facilities that expire in 2007 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. 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.

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 statements of income. Capacity payments totaled $49 million, $54 million, and $55 million in 2006, 2005, and 2004, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2007	$ 49
2008	49
2009	54
2010	54
2011	54
2012 and thereafter	200
Total	$ 460

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 under these commitments at December 31, 2006 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2007	$ 220	$ 86
2008	220	87
2009	220	94
2010	112	96
2011	65	98
2012 and thereafter	390	665
Total	$ 1,227	$ 1,126

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $33 million for 2006, $39 million for 2005, and $39 million for 2004.

At December 31, 2006, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
	(in millions)		
2007	$ 18	$ 14	$ 32
2008	18	11	29
2009	16	10	26
2010	15	7	22
2011	16	6	22
2012 and thereafter	32	10	42
Total	$ 115	$ 58	$ 173

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 $64 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

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations 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.

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

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 these 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, 2006, 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.

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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, 2006 and 2005, the Company had a capitalized lease obligation for its corporate headquarters building of $72 million and $74 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. See Note 1 under "Regulatory Assets and Liabilities." At December 31, 2006 and 2005, the Company had capitalized lease obligations for its Plant Kraft coal unloading dock and its vehicles of $4.1 million and $5.1 million, respectively. However, for ratemaking purposes, these obligations are treated as operating leases and, as such, lease payments are charged to expense as incurred. The annual expense incurred for these leases in 2006, 2005, and 2004 was $9.6 million, $9.7 million, and $9.6 million, respectively.

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At the beginning of 2007, the Company had credit arrangements with banks totaling $910 million, of which $904 million was unused. Of these facilities, $40 million expires during 2007, with the remaining $870 million expiring in 2011. The facilities that expire in 2007 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. 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.

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. At December 31, 2006, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $904 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, 2006 was $112 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, 2006 was $733 million. The amount of commercial paper outstanding at December 31, 2005 was $327 million. There were no outstanding extendible commercial notes at December 31, 2006. Commercial paper is included in notes payable on the balance sheets.

During 2006, the peak amount of short-term debt outstanding was $757 million and the average amount outstanding was $549 million. The average annual interest rate on short-term debt in 2006 was 5.1 percent.

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. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, and 2004.

At December 31, 2006, the fair value gains /(losses) of derivative energy contracts were reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	$ (38.0)
Net income	–
Total fair value	$ (38.0)

The fair value gain or loss for 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 2009.

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 employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings. Subsequent to December 31, 2006, the Company entered into $375 million notional amounts of interest rate swaps to hedge unfavorable changes in interest rates. The hedges will be terminated at the time the underlying debt is issued. In addition to interest rate swaps, the Company has also entered into certain option 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, 2006, the Company had $1.2 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/(Loss)
		(in millions)	
2007	2.68%	$ 300	$ 1.4
2007	3.85%*	400	0.1
2017	5.29%	225	(2.0)
2037	5.75%*	300	1.4
2007	2.50%**	14	0.2

* Interest rate collar (showing only the rate cap percentage)

** Hedged using the Bond Market Association Municipal Swap Index

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 2006, 2005, and 2004, the Company settled gains (losses) totaling $(3.9) million, $0.9 million, and $(12.4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2006, 2005, and 2004, approximately $1.1 million, $(1.9) million, and $(3.9) million, respectively, of pre-tax gains/(losses) were reclassified from other comprehensive income to interest expense. For 2007, no material pre-tax losses are expected to be reclassified from other comprehensive income to interest expense. The Company has interest related hedges in place through 2037 and has realized gains/(losses) that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.9 billion, $1.8 billion, and $1.8 billion in 2007, 2008, and 2009, respectively. These amounts include $94 million, $73 million, and $88 million in 2007, 2008, and 2009, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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 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, 2006, significant purchase commitments were outstanding in connection with the construction program.

Long-Term Service Agreements

The Company has 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 combined 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 quarterly based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $198.5 million over the remaining term of the agreement, which is currently projected to be approximately 12 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $12.2 million. The contract contains cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

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. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. 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, 2006.

Total estimated minimum long-term obligations at December 31, 2006 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
	(in millions)		
2007	$ 647	$ 1,638	$ 94
2008	534	1,463	73
2009	342	983	88
2010	202	330	121
2011	262	62	101
2012 and thereafter	1,914	44	169
Total	$ 3,901	$ 4,520	$ 646

Additional commitments for 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 traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power 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 statements of income. Capacity payments totaled $49 million, $54 million, and $55 million in 2006, 2005, and 2004, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2007	$ 49
2008	49
2009	54
2010	54
2011	54
2012 and thereafter	200
Total	$ 460

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 under these commitments at December 31, 2006 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2007	$ 220	$ 86
2008	220	87
2009	220	94
2010	112	96
2011	65	98
2012 and thereafter	390	665
Total	$ 1,227	$ 1,126

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $33 million for 2006, $39 million for 2005, and $39 million for 2004.

At December 31, 2006, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
	(in millions)		
2007	$ 18	$ 14	$ 32
2008	18	11	29
2009	16	10	26
2010	15	7	22
2011	16	6	22
2012 and thereafter	32	10	42
Total	$ 115	$ 58	$ 173

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 $64 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

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations 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.

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 the Company's employees ranging from line management to executives. As of December 31, 2006, there were 1,651 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 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. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however for employees who are eligible for retirement the total cost is expensed at the grant date. 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. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed earlier in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options that were used under SFAS No. 123.

The Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject to Option	Weighted-Average Exercise Price
Outstanding at December 31, 2005	7,223,875	$ 26.87
Granted	1,431,489	33.81
Exercised	(811,013)	24.02
Cancelled	(13,768)	30.97
Outstanding at December 31, 2006	**7,830,583**	**$ 28.42**
Exercisable at December 31, 2006	**5,106,339**	**$ 26.14**

The number of stock options vested, and expected to vest in the future, at December 31, 2006 is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

At December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.4 years and 5.3 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $66 million and $55 million, respectively.

As of December 31, 2006, there was $2.5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $10 million, $24 million, and $16 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $9 million, and $6 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), 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. A company could be assessed up to $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $30 million to be paid for each incident in any one year.

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 the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL subject to ownership limitations and has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $49 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, 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, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property 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 nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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 2006 and 2005 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2006	**$ 1,584**	**$ 288**	**$ 132**
June 2006	**1,808**	**386**	**197**
September 2006	**2,275**	**662**	**382**
December 2006	**1,579**	**174**	**76**
March 2005	$ 1,459	$ 290	$ 144
June 2005	1,554	325	164
September 2005	2,369	661	375
December 2005	1,694	172	61

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

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SELECTED FINANCIAL AND OPERATING DATA 2002-2006

Georgia Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	$ **7,245,644**	$ 7,075,837	$ 5,727,768	$ 5,228,625	$ 5,119,466
Net Income after Dividends on Preferred Stock (in thousands)	$ **787,225**	$ 744,373	$ 682,793	$ 654,036	$ 638,948
Cash Dividends on Common Stock (in thousands)	$ **630,000**	$ 582,800	$ 588,700	$ 588,800	$ 565,600
Return on Average Common Equity (percent)	**13.80**	14.08	13.87	14.01	13.92
Total Assets (in thousands)	$ **19,308,730**	$ 17,898,445	$ 16,598,778	$ 15,527,223	$ 14,978,520
Gross Property Additions (in thousands)	$ **1,276,889**	$ 958,563	$ 1,252,197	$ 783,053	$ 916,449
Capitalization (in thousands):					
Common stock equity	$ **5,956,251**	$ 5,452,083	$ 5,123,276	$ 4,723,299	$ 4,610,396
Preferred stock	**44,991**	43,909	58,547	14,569	14,569
Mandatorily redeemable preferred securities	**–**	–	–	940,000	980,000
Long-term debt payable to affiliated trusts	**969,073**	969,073	969,073	–	–
Long-term debt	**4,242,839**	4,396,250	3,947,621	3,984,825	3,277,671
Total (excluding amounts due within one year)	$ **11,213,154**	$ 10,861,315	$ 10,098,517	$ 9,662,693	$ 8,882,636
Capitalization Ratios (percent):					
Common stock equity	**53.1**	50.2	50.7	48.9	51.9
Preferred stock	**0.4**	0.4	0.6	0.2	0.2
Mandatorily redeemable preferred securities	**–**	–	–	9.7	11.0
Long-term debt payable to affiliated trusts	**8.6**	8.9	9.6	–	–
Long-term debt	**37.9**	40.5	39.1	41.2	36.9
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	Baa1
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	**1,998,643**	1,960,556	1,926,215	1,890,790	1,854,561
Commercial	**294,654**	289,009	283,507	275,378	267,505
Industrial	**8,008**	8,290	7,765	7,989	8,321
Other	**4,371**	4,143	4,015	3,940	3,822
Total	**2,305,676**	2,261,998	2,221,502	2,178,097	2,134,209
Employees (year-end)	**9,278**	9,273	9,294	9,263	9,385

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2002-2006 (continued)

Georgia Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	$ **2,326,190**	$ 2,227,137	$ 1,900,961	$ 1,726,543	$ 1,738,206
Commercial	**2,423,568**	2,357,077	1,933,004	1,767,487	1,734,423
Industrial	**1,382,213**	1,406,295	1,217,536	1,051,034	1,036,722
Other	**73,649**	73,854	67,250	63,715	61,972
Total retail	**6,205,620**	6,064,363	5,118,751	4,608,779	4,571,323
Sales for resale – non-affiliates	**551,731**	524,800	251,581	265,029	277,031
Sales for resale – affiliates	**252,556**	275,525	172,375	181,355	102,398
Total revenues from sales of electricity	**7,009,907**	6,864,688	5,542,707	5,055,163	4,950,752
Other revenues	**235,737**	211,149	185,061	173,462	168,714
Total	$ **7,245,644**	$ 7,075,837	$ 5,727,768	$ 5,228,625	$ 5,119,466
Kilowatt-Hour Sales (in thousands):					
Residential	**26,206,170**	25,508,472	24,829,833	23,532,467	23,900,526
Commercial	**32,112,430**	31,334,182	29,553,893	28,401,764	28,409,596
Industrial	**25,577,006**	25,832,265	27,197,843	26,564,261	26,531,207
Other	**660,285**	737,343	744,935	732,900	731,115
Total retail	**84,555,891**	83,412,262	82,326,504	79,231,392	79,572,444
Sales for resale – non-affiliates	**12,314,322**	11,318,403	6,101,243	8,998,272	8,220,170
Sales for resale – affiliates	**5,494,436**	5,033,165	4,925,744	6,029,398	4,088,440
Total	**102,364,649**	99,763,830	93,353,491	94,259,062	91,881,054
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.88**	8.73	7.66	7.34	7.27
Commercial	**7.55**	7.52	6.54	6.22	6.11
Industrial	**5.40**	5.44	4.48	3.96	3.91
Total retail	**7.34**	7.27	6.22	5.82	5.74
Sales for resale	**4.52**	4.89	3.84	2.97	3.08
Total sales	**6.85**	6.88	5.94	5.36	5.39
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,216**	13,119	13,002	12,555	12,990
Residential Average Annual Revenue Per Customer	$ **1,173**	$ 1,145	$ 995	$ 921	$ 945
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,995**	15,995	14,743	14,768	14,847
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,528**	14,360	13,087	13,929	12,539
Summer	**17,159**	16,925	16,129	15,575	15,896
Annual Load Factor (percent)	**61.8**	59.4	61.0	61.6	61.6
Plant Availability (percent):					
Fossil-steam	**91.4**	90.0	87.1	85.9	81.1
Nuclear	**90.7**	89.3	94.8	94.1	88.8
Source of Energy Supply (percent):					
Coal	**58.0**	60.0	57.0	57.9	58.8
Nuclear	**14.2**	14.4	16.4	16.0	15.4
Hydro	**0.9**	1.8	1.5	2.0	0.8
Oil and gas	**4.8**	3.0	0.1	0.3	0.5
Purchased power –					
From non-affiliates	**6.2**	5.6	7.0	7.3	6.2
From affiliates	**15.9**	15.2	18.0	16.5	18.3
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Automotive Group
(resigned effective 2/21/06)

Gus H. Bell III
Chairman and President
Hussey, Gay, Bell and DeYoung
(elected effective 5/17/06)

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
Chairman, President and Chief Executive Officer
The Southern Company

Jimmy C. Tallent - ***Nominee***
President and Chief Executive Officer
United Community Banks, Inc.

D. Gary Thompson
Retired from Wachovia Corporation

Richard W. Ussery
Retired from Total System Services, Inc.

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

William C. Archer III
Executive Vice President
External Affairs
(retired effective 3/19/06)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President
External Affairs
(elected effective 3/11/06)

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President
Customer Service and Sales
(elected effective 1/14/06)

Douglas E. Jones
Senior Vice President
Fossil and Hydro Generation and
Senior Production Officer

James H. Miller III
Senior Vice President and
General Counsel

Michael K. Anderson
Vice President
Corporate Services
(elected effective 1/14/06)

DIRECTORS AND OFFICERS

W. Craig Barrs
Region Vice President
Coastal

Robert A. Bell
Vice President
Human Resources
(elected effective 2/15/06)

Rebecca A. Blalock
Vice President
Information Resources

P. Michael Clanton
Vice President
Customer Service
(elected effective 1/14/06)

Ann P. Daiss
Vice President, Comptroller and Chief Accounting Officer
(elected effective 3/11/06)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President
Governmental & Regulatory Affairs and
Resource Planning & Nuclear Development
(elected effective 2/11/06)

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer
(resigned effective 3/11/06)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs
(retired effective 12/31/06)

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President
Human Resources
(resigned effective 2/1/06)

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Leslie R. Sibert
Vice President
Transmission

James E. Sykes, Jr.
Region Vice President
Northeast

Gene L. Ussery, Jr.
Vice President
Distribution
(retired effective 4/1/07)

Jeffrey L. Wallace
Vice President
Planning & Utility Relations
(resigned effective 2/11/06)

Thomas J. Wicker
Region Vice President
Central

DIRECTORS AND OFFICERS

Anthony L. Wilson
Vice President
Distribution
(elected effective 2/10/07)

W. Tal Wright
Vice President
Corporate Communication

E. Wayne Boston
Assistant Secretary and
Assistant Treasurer

Robert B. Morris
Assistant Comptroller and Assistant Secretary

Mark K. Tate
Assistant Comptroller

CORPORATE INFORMATION
Georgia Power Company 2006 Annual Report

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 approximately 2.3 million customers within its service area. In 2006, retail energy sales accounted for 83 percent of the Company's total sales of 102.4 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional 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
The Bank of New York
Global Trust Administration
101 Barclay Street, 8 West
New York, New York 10286

Registrar, Transfer Agent and Dividend Paying Agent
6 1/8% Series Class A Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

All of the outstanding shares of the Company's preferred stock are registered in the name of Cede & Co., as nominee for The Depository Trust Company.

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 at 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308-3374. For additional information, contact the office of the Corporate Secretary at (404) 506-6410.

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

END