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2006 *Annual Report*

Alabama Power Company

ALABAMA POWER
A SOUTHERN COMPANY

Always on.℠

100 years. Lighting the way.

CONTENTS

Alabama Power Company 2006 Annual Report

SUMMARY

	2006	2005	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$5,015**	$4,648	7.9
Operating expenses	**$3,905**	$3,634	7.5
Net income after dividends on preferred and preference stock	**$518**	$508	1.9
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**56,375**	55,684	1.2
Sales for resale - non-affiliates	**15,978**	15,443	3.5
Sales for resale - affiliates	**5,145**	5,735	(10.3)
Total	**77,498**	76,862	0.8
Customers served at year-end *(in thousands)*	**1,416**	1,403	0.9
Peak-hour demand *(in megawatts)*	**11,744**	11,162	5.2
Capitalization Ratios *(percent)*:			
Common stock equity	**45.9**	46.7	
Preferred and preference stock	**7.0**	5.7	
Long-term debt payable to affiliated trusts	**3.5**	3.8	
Long-term debt (Excluding long-term debt due within one year)	**43.6**	43.8	
Return on Average Common Equity *(percent)*	**13.23**	13.72	

2006 Letter to Investors

As Alabama Power entered its second century of service, I am proud to report that we continued our legacy of keeping our commitments to our shareholders, our customers and the communities we serve.

Thankfully, 2006 did not bring the devastating storms we've faced in recent years. Still, 2006 was not without its challenges. We saw sharp increases in the price of fuel, steel, copper and other materials that are essential to our business. Through stellar employees and an emphasis on controlling costs across the company, we were able to meet all of our financial goals and continue to offer our customers prices well below the national average.

Alabama Power continued to produce outstanding results in virtually every area in 2006. Despite a record demand for electricity during the summer, more stringent environmental requirements and fuel supply issues, our generating plants set a new record for availability during the peak season. Because of our excellent transmission and distribution system, our reliability rate remained at 99.9 percent. We again ranked in the upper quartile in customer satisfaction among peer utilities.

We continued to install new equipment and technology to further reduce emissions of nitrogen oxide, sulfur dioxide and mercury from our generating plants and to protect the environment. In addition, Alabama Power's Renew Our Rivers program was honored for the second time by the national Keep America Beautiful organization.

I am proud of our accomplishments in 2006 and of the fact that, in our centennial year, Alabama Power lived up to its legacy of service and excellence. But Alabama Power employees understand that we cannot rest on past achievements. Both the world and our business are constantly changing. Be assured that Alabama Power is prepared to meet the challenges ahead in the same manner we have met the challenges of the past – honestly, ethically and with the best interests of all of our stakeholders in mind.

Sincerely,

Charles D. McCrary
President and Chief Executive Officer
April 9, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama 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 23 to 50) present fairly, in all material respects, the financial position of Alabama 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 Alabama Power Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Birmingham, Alabama
February 26, 2007

OVERVIEW

Business Activities

Alabama 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 Alabama and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and restoration following major storms.

In December 2006, the Company filed for an increase in retail base rates under Rate Stabilization and Equalization Plan (Rate RSE) based on a forward-looking test period. This increase became effective with billings beginning in January 2007. This and other regulatory actions are expected to assist the Company's continued focus on providing reliable electrical service to customers while maintaining a stable financial position.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. 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. 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. The performance for 2006 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 with its targets for each 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**
Peak Season EFOR	2.75% or less	**0.76%**
Net Income	$502 million	**$518 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 financial performance remained strong in 2006 despite the challenges of rising costs. The Company's net income after dividends on preferred and preference stock of $518 million in 2006 increased $10 million (1.9 percent) over the prior year. This improvement is primarily due to retail and wholesale revenue growth offset by higher non-fuel operating expenses and increased interest expense.

The Company's 2005 net income after dividends on preferred stock was $508 million, representing a $27 million (5.6 percent) increase from the prior year. This improvement was primarily due to retail and wholesale revenue growth and increases in transmission revenues, partially offset by higher non-fuel operating expenses.

The Company's 2004 net income after dividends on preferred stock was $481 million, representing an $8 million (1.8 percent) increase from the prior year. This improvement was primarily due to retail sales growth, increases in other revenues, and lower interest expense, partially offset by higher non-fuel operating expenses.

RESULTS OF OPERATIONS

A condensed income statement is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
		(in millions)		
Operating revenues	**$5,015**	**$ 367**	$ 412	$ 276
Fuel	**1,673**	**216**	271	119
Purchased power	**426**	**(31)**	44	98
Other operations and maintenance	**1,097**	**53**	97	26
Depreciation and amortization	**451**	**24**	1	13
Taxes other than income taxes	**258**	**9**	6	14
Total operating expenses	**3,905**	**271**	419	270
Operating income	**1,110**	**96**	(7)	6
Total other income and (expense)	**(237)**	**(40)**	6	30
Income taxes	**330**	**46**	(29)	23
Net income	**543**	**10**	28	13
Dividends on preferred and preference stock	**25**	**-**	1	5
Net income after dividends on preferred and preference stock	**$ 518**	**$ 10**	$ 27	$ 8

Revenues

Operating Revenues

Operating revenues for 2006 were $5.0 billion, reflecting a $367 million increase from 2005. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2006	2005	2004
		(in millions)	
Retail -- prior year	**$ 3,621**	$ 3,293	$3,051
Change in -			
Base rates	**43**	35	41
Sales growth	**42**	50	48
Weather	**20**	18	12
Fuel cost recovery and other	**270**	225	141
Retail -- current year	**3,996**	3,621	3,293
Sales for resale --			
Non-affiliates	**635**	551	484
Affiliates	**216**	289	308
Total sales for resale	**851**	840	792
Other operating revenues	**168**	187	151
Total operating revenues	**$ 5,015**	$ 4,648	$4,236
Percent change	**7.9%**	9.7%	7.0%

Retail revenues in 2006 were $4.0 billion. These revenues increased $375 million (10.3 percent) in 2006, $328 million (10.0 percent) in 2005, and $242 million (7.9 percent) in 2004. These increases were primarily due to increased fuel revenue and retail base rate increases of 2.6 percent in January 2006, 1.0 percent in January 2005, and 0.8 percent in July 2004. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Sales for resale to non-affiliates are predominantly unit power sales under long-term contracts to Florida utilities. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales customers, influence changes in these sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. These capacity and energy components of the unit power sales contracts were as follows:

	2006	2005	2004
		(in thousands)	
Unit power -			
Capacity	**$ 153,581**	$ 147,609	$ 134,615
Energy	**198,189**	169,080	146,809
Total	**$ 351,770**	$ 316,689	$ 281,424

No significant declines in the amount of capacity revenues are scheduled until the termination of the contracts in May 2010.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. Revenues associated with other power sales to non-affiliates were as follows:

	2006	2005	2004
		(in thousands)	
Other power sales -			
Capacity and other	**$ 136,966**	$ 116,181	$ 90,673
Variable cost of energy	**145,816**	118,537	111,742
Total	**$ 282,782**	$ 234,718	$ 202,415

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, sales for resale revenues decreased $72.9 million primarily due to a 16.7 percent decrease in price and a 10.3 percent decrease in kilowatt-hour (KWH) sales to affiliates as a result of a decrease in the availability of the Company's generating resources because of an increase in customer demand within the Company's service territory. In 2005, sales for resale revenues decreased $19.4 million primarily due to a 20.7 percent decrease in KWH sales to affiliates as a result of a decrease in the availability of the Company's generating resources due to an increase in customer demand within the Company's service territory. Sales for resale revenues increased $31.1 million in 2004 due to increases in fuel-related expenses. Excluding the capacity revenues, these transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

Other operating revenues in 2006 decreased $17.6 million (9.5 percent) from 2005 primarily due to a decrease of $14.6 million in revenues from gas-fueled co-generation steam facilities primarily as a result of lower gas prices. In 2005, other operating revenues increased $35.0 million (23.2 percent) from 2004 due to an increase of $20 million in revenues from gas-fueled co-generation steam facilities primarily as a result of higher gas prices, a $7.7 million increase in transmission revenues, and a $3.9 million increase from rent from associated companies primarily related to leased transmission facilities. Other operating revenues in 2004 increased $7.0 million (4.9 percent) from 2003 due to an increase of $7.7 million in revenues from gas-fueled co-generation steam facilities primarily as a result of higher gas prices, and a $2.4 million increase in revenues from rent from electric property offset by a $2.0 million decrease in transmission revenues. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

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

	KWH	Percent Change		
	2006	2006	2005	2004
	(in millions)			
Residential	**18,633**	**3.1%**	4.1%	2.4%
Commercial	**14,355**	**2.1**	1.7	2.8
Industrial	**23,187**	**(0.7)**	2.2	5.8
Other	**200**	**0.4**	0.2	(2.4)
Total retail	**56,375**	**1.2**	2.7	3.9
Sales for resale -				
Non-affiliates	**15,978**	**3.5**	(0.3)	(9.4)
Affiliates	**5,145**	**(10.3)**	(20.7)	(23.2)
Total	**77,498**	**0.8**	(0.1)	(2.2)

Retail energy sales in 2006 were 1.2 percent higher than in 2005. Energy sales in the residential and commercial sectors led the growth with a 3.1 percent and a 2.1 percent increase, respectively, in 2006 due primarily to weather-driven increased demand. Industrial sales decreased 0.7 percent during the year as several large textile facilities discontinued or substantially reduced their operations in 2006. In addition, industrial sales decreased due to pulp and paper customers utilizing self-generation as a result of lower gas prices during the year compared to 2005.

Retail energy sales in 2005 were 2.7 percent higher than 2004 despite interruptions during Hurricanes Dennis and Katrina. Energy sales in the residential sector led the growth with a 4.1 percent increase in 2005 due primarily to increased demand. Commercial sales increased 1.7 percent in 2005 primarily due to continued customer growth. Industrial sales increased 2.2 percent during the year with chemical, primary metals and automotive leading the growth in industrial energy consumption. In addition, the paper sector chose to purchase rather than self-generate which contributed to increased sales.

Retail energy sales in the residential sector grew by 2.4 percent in 2004 primarily due to continued customer growth and a return to normal summer temperatures. Commercial sales increased 2.8 percent in 2004 primarily due to continued customer growth. Industrial sales rebounded 5.8 percent during the year with primary metals, chemical, and paper sectors leading the growth.

Expenses

Fuel and Purchased Power

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) --	**72.0**	71.2	70.2
Total purchased power (billions of KWH) --	**8.9**	8.7	10.2
Sources of generation (percent) --			
Coal	**68**	67	65
Nuclear	**19**	19	19
Gas	**9**	8	10
Hydro	**4**	6	6
Average cost of fuel, source (cents per net KWH) --			
Coal	**2.09**	1.85	1.58
Nuclear	**0.47**	0.46	0.46
Gas	**7.87**	7.43	4.69
Average cost of fuel, generated (cents per net KWH) --	**2.27**	2.02	1.69
Average cost of purchased power (cents per net KWH) --	**5.98**	6.49	4.79

Fuel and purchased power expenses were $2.1 billion in 2006, an increase of $184.1 million (9.6 percent) above the prior year costs. This increase was the result of a $128.7 million increase in the cost of fuel and a $55.4 million increase related to total KWH generated and purchased.

Fuel and purchased power expenses were $1.9 billion in 2005, an increase of $315.4 million (19.7 percent) above the prior year costs. This increase was the result of a $367.4 million increase in the cost of fuel offset by a $52.0 million decrease related to total KWH generated and purchased.

Fuel and purchased power expenses were $1.6 billion in 2004, an increase of $216.3 million (15.6 percent) above the prior year costs. This increase was the result of a $218.4 million increase in the cost of fuel offset by a $2.1 million decrease related to total KWH generated and purchased.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. Purchased power from non-affiliates decreased $64.7 million (34.3 percent) in 2006. This decrease was due to a 26.8 percent decrease in the amount of energy purchased and a 10.3 percent decrease in purchased power prices over the previous year. In 2005, purchased power from non-affiliates increased $2.5 million (1.0 percent) due to a 14.3 percent increase in purchased power prices over the previous year. In 2004, purchased power from non-affiliates increased $75 million (68.0 percent) due to a 71.7 percent increase in energy purchased offset by a 1.9 percent decrease in purchased power prices compared to 2003.

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 energy cost recovery clause. The Company continuously monitors the under/over recovered balance and files for a revised fuel rate when management deems appropriate. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Other Operating Expenses

Other Operations and Maintenance

In 2006, other operations and maintenance expenses increased $52.8 million (5.1 percent) primarily due to an $18.8 million increase in administrative and general expenses related to employee benefits, a $10.1 million increase in nuclear production expense related to both routine operation and scheduled outage costs, a $9.8 million increase in transmission and distribution expense related to overhead and underground line costs, and a $5.4 million increase in steam production expense related to environmental costs. In 2005, other operations and maintenance expenses increased $96.7 million (10.2 percent). This increase was primarily due to an increase in transmission and distribution expense of $37.3 million as a result of the Alabama Public Service Commission (PSC) accounting order to offset the costs of the damage from Hurricane Ivan in September 2004 and to restore a balance in the natural disaster reserve. See Notes 1 and 3 to the financial statements under "Natural Disaster Reserve" and "Natural Disaster Cost Recovery," respectively, for additional information. In addition, steam production expense increased $28.1 million related to scheduled outage costs and administrative and general expenses increased $20.7 million related to employee benefits. In 2004, other operations and maintenance expenses increased $26.6 million (2.9 percent) primarily due to an increase in administrative and general expenses related to employee benefits.

Depreciation and Amortization

Depreciation and amortization expenses increased $24.5 million (5.7 percent) in 2006 primarily due to additions to property, plant, and equipment. In 2005, depreciation and amortization expenses remained relatively flat compared to the prior year, increasing only $0.6 million (0.1 percent). During 2005, the depreciation rates used by the Company were adjusted based on a periodic study conducted by external experts that is used to determine the appropriateness of the rates utilized. Also in 2005, additions to property, plant, and equipment, which resulted in increased depreciation expense, were offset by the suspension of $18 million in nuclear decommissioning costs by the Alabama PSC due to the extension of the operating license for both units at Plant Farley. See FUTURE EARNINGS POTENTIAL – "Nuclear Relicensing" and Note 1 to the financial statements under "Nuclear Decommissioning" for additional information. In 2004, depreciation and amortization expenses increased $13 million (3.1 percent) primarily due to an increase in utility plant in service. This increase reflects the impact of additions to property, plant, and equipment.

Taxes other than Income Taxes

Taxes other than income taxes increased $9.3 million (3.7 percent) in 2006, $6.0 million (2.5 percent) in 2005, and $14.4 million (6.3 percent) in 2004, primarily due to increases in state and municipal public utility license taxes which are directly related to the increase in retail revenues.

Other Income and (Expense)

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) decreased $2.0 million (10.0 percent) in 2006 primarily due to the timing of construction expenditures compared to the prior year. AFUDC increased $4.1 million (25.6 percent) and $3.5 million (28.2 percent) in 2005 and 2004, respectively, primarily due to increases in the amount of construction work in progress over the prior year. See Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest

Interest expense, net of amounts capitalized increased $38.7 million (19.6 percent) in 2006 primarily due to higher interest rates and an increase in the average debt outstanding during the year. Interest expense, net of amounts capitalized, increased $3.8 million (2.0 percent) in 2005 due to an increase in average debt outstanding during the year. Interest expense, net of amounts capitalized, decreased $20.7 million (9.7 percent) in 2004 due to refinancing activities.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. Rate RSE is based on annual projected costs, including estimates for inflation. When historical costs are included, or when inflation exceeds the 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, the income tax laws are based on historical costs. The inflation rate has been relatively low in recent years and any adverse effect of inflation on the Company has not been substantial.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in the State of Alabama and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for electricity relating to purchased power agreements (PPAs), interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under

"FERC Matters" and "Retail Regulatory 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 primary business of selling electricity. These factors include the Company's ability 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, sales to retail customers are projected to grow approximately 1.1 percent annually on average during 2007 through 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, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama after the Company was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at five coal-fired generating facilities operated by the Company. 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 the Company and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required the Company 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 the Company, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company 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 the 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 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 Alabama. 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 Alabama'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.

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 $1.2 billion in capital projects to comply with these requirements, with annual totals of $260 million, $256 million, and $177 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 $505 million, $533 million, and $549 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 impact of compliance 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 $1.0 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 $638 million of these expenditures related to reducing NO_x emissions pursuant to state and federal requirements were in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. In 2004, the regional NO_x reduction rules were implemented for the northern two-thirds of Alabama. See Note 3 to the financial statements under "Retail Regulatory Matters" for information regarding the Company's recovery of costs associated with environmental laws and regulations.

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 included Jefferson and Shelby Counties, near and including Birmingham. The Birmingham area was redesignated to attainment with the eight-hour ozone standard by the EPA on June 12, 2006, and the EPA subsequently approved a maintenance plan for the area to address future exceedances of the standard. 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 most areas 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 Alabama, 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, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

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.

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 $3.9 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 $14.6 million for the Company, of which $3.1 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 the Company, Georgia Power, 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 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 two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11 million previously paid for interconnection facilities, with interest. The 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.

Hydro Relicensing

In July 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expire in July and August of 2007.

In 2006, the Company initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license will be filed with the FERC in 2011.

Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. If the FERC does not act on the Company's new license application prior to the expiration of the existing license, then the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until a new license is issued.

The timing and final outcome of the Company's relicense applications cannot now be determined.

Nuclear Relicensing

The Company filed an application with the Nuclear Regulatory Commission (NRC) in September 2003 to extend the operating license for Plant Farley for an additional 20 years. In May 2005, the NRC granted the Company a 20-year extension of the operating license for both units at Plant Farley. As a result of the license extension, amounts previously contributed to the external trust are currently projected to be adequate to meet the decommissioning obligations. Therefore, in June 2005, the Alabama PSC approved the Company's request to suspend, effective January 1, 2005, the inclusion in its annual cost of service of $18 million in decommissioning costs and to also suspend the associated obligation to make semi-annual contributions to the external trust. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

PSC Matters

Retail Rate Adjustments

In October 2005, the Alabama PSC approved a revision to the Rate RSE requested by the Company. Effective January 2007 and thereafter, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4 percent per year and any annual adjustment is limited to 5 percent. Rates remain unchanged when the projected return on retail common equity ranges between 13.0 percent and 14.5 percent. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range. The Company made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007, effective in January, is 4.76 percent, or $193 million annually. Under terms of Rate RSE, the maximum increase for 2008 cannot exceed 3.24 percent. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for further information.

The Company's retail rates, approved by the Alabama PSC, also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under Rate Certificated New Plant (Rate CNP). In October 2004, the Alabama PSC amended Rate CNP to also allow for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism began operation in January 2005 and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operation and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.0 percent in January 2005, 1.2 percent in January 2006, and 0.6 percent in January 2007. It is currently anticipated that retail rates will increase approximately 2.5 percent in 2008.

Effective July 2004, the Company's retail rates were increased by approximately 0.8 percent, or $25 million annually, under Rate CNP for new certificated PPAs. In April 2005, an annual adjustment to Rate CNP decreased retail rates by approximately 0.5 percent, or $19 million annually. The annual true-up adjustment effective in April 2006 increased retail rates by 0.5 percent, or $19 million annually. Based on the Company's February 2007 filing, there will be no rate adjustment associated with the annual true-up adjustment in April 2007. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. As a result of increased fuel costs for coal, gas, and uranium, the Company filed a fuel cost recovery increase under the provisions of its energy cost recovery rate (Rate ECR). In December 2005, the Alabama PSC approved an increase of the energy billing factor for retail customers from 1.788 cents per KWH to 2.400 cents per KWH, effective with billings beginning January 2006 for the 24-month period ending December 31, 2007. Thereafter, the Rate ECR factor will increase absent a contrary order by the Alabama PSC. This change to the billing factor in 2006 represents on average an increase of approximately $6.12 per month for a customer billing of 1,000 KWH. This approved increase was intended to allow for the recovery of energy costs based on an estimate of future energy costs, as well as the collection of the existing under recovered energy costs by the end of 2007. In addition, during 2007, the Company will be allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation.

The Company's under recovered fuel costs as of December 31, 2006 totaled $301.0 million as compared to $285.1 million at December 31, 2005. As a result of the Alabama PSC order, the Company reclassified $301.0 million and $186.9 million of the under-recovered regulatory clause revenues from current assets to deferred charges and other assets in the balance sheets as of December 31, 2006 and December 31, 2005, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable costs and amounts billed in current regulated rates. Accordingly, this approved increase in the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

Natural Disaster Cost Recovery

The Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. On July 10, 2005 and August 29, 2005, Hurricanes Dennis and Katrina, respectively, hit the coast of Alabama and continued north through the state, causing significant damage in parts of the service territory of the Company. Approximately 241,000 and 637,000 of the Company's 1.4 million customers were without electrical service immediately after Hurricanes Dennis and Katrina, respectively. The Company sustained significant damage to its distribution and transmission facilities during these storms.

In August 2005, the Company received approval from the Alabama PSC to defer the Hurricane Dennis storm-related operations and maintenance costs (approximately $28 million), which resulted in a negative balance in the natural disaster reserve (NDR). In October 2005, the Company also received similar approval from the Alabama PSC to defer the Hurricane Katrina storm-related operations and maintenance costs (approximately $30 million). See Note 1 and Note 3 to the financial statements under "Natural Disaster Reserve" and "Natural Disaster Cost Recovery," respectively, for additional information on these reserves. The natural disaster reserve deficit balance at December 31, 2005 was $50.6 million.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted NDR and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components beginning in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. Assuming no additional storms, the Company currently expects that the target reserve balance could be achieved within five years. The second component of the NDR charge is intended to allow recovery of the existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

As of December 31, 2006, the Company had recovered $49.5 million of the costs allowed for storm-recovery activities and the deficit balance in the natural disaster reserve account totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of the NDR charge. At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities."

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income but will increase annual cash flow.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pre-tax pension income of approximately $13 million, $21 million, and $36 million in 2006, 2005, and 2004, respectively. Postretirement benefit costs for the Company were $28 million, $28 million, and $22 million in 2006, 2005, and 2004, respectively. Postretirement benefit costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters 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 critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama 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 under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines 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 Alabama 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," using the modified prospective method. This statement requires that compensation cost relating to share-based payment transactions be recognized in 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 $183 million with respect to its overfunded defined benefit plan and additional liabilities of $10 million and $147 million, respectively, related to its underfunded non-qualified pension plans and other postretirement 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. The adoption of FIN 48 did not have a 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. Net cash flow from operating activities totaled $956 million, $908 million, and $1,014 million for 2006, 2005, and 2004, respectively. The $48 million increase for 2006 in operating activities primarily relates to higher recovery rates for fuel and purchased power partially offset by the timing of payments for operation expenses. The $106 million decrease for 2005 in operating activities primarily relates to an increase in under recovered fuel cost and storm damage costs related to Hurricanes Dennis and Katrina. These increases were partially offset by the deferral of income tax liabilities arising from accelerated depreciation deductions. Fuel and storm damage costs are recoverable in future periods. Under recovered fuel cost is included in the balance sheets as under recovered regulatory clause revenue and deferred under recovered regulatory clause revenues. Under recovered storm damage cost is included in the balance sheets as other current assets and other regulatory assets. See FUTURE EARNINGS POTENTIAL – "Retail Fuel Cost Recovery" and "Natural Disaster Cost Recovery" for additional information.

Significant balance sheet changes for 2006 include an increase of $697 million in gross plant and an increase of $279 million in long-term debt. In 2005, significant balance sheet changes included an increase of $668 million in gross plant.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.1 percent in 2006, 42.2 percent in 2005, and 42.6 percent in 2004. See Note 6 to the financial statements for additional information.

The Company has maintained investment grade ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference 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. In recent years, the Company has primarily utilized unsecured debt, common stock, preferred and preference stock, and preferred securities. However, the type and timing of any financings, if needed, will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. 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 Alabama 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 to meet scheduled maturities of long-term debt as well as cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2007, the Company had approximately $16 million of cash and cash equivalents and $965 million of unused credit arrangements with banks, as described below. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including commercial paper programs, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of $965 million, of which $365 million will expire at various times during 2007. $198 million of the credit facilities expiring in 2007 allow for the execution of term loans for an additional one-year period. The remaining $600 million of credit facilities expire in 2011. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other 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 such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

As of December 31, 2006, the Company had $120 million in commercial paper outstanding, and no extendible commercial notes outstanding. As of December 31, 2005, the Company had $136 million in commercial paper outstanding, $55 million in extendible commercial notes outstanding, and $125 million in loans outstanding under an uncommitted credit arrangement.

Financing Activities

During 2006, the Company issued $950 million of long-term debt and six million new shares of preference stock at $25.00 stated capital per share and realized proceeds of $150 million. In addition, the Company issued three million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $120 million. The proceeds of these issuances were used to repay $546.5 million of senior notes and $3.0 million of obligations related to pollution control bonds, to repay short-term indebtedness, and for other general corporate purposes.

On February 6, 2007, the Company issued $200 million of long-term senior notes. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

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. However, the Company, along with all members of the Southern Company power pool, is 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 Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price Risk

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company 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 testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps that have been designated as hedges. The weighted average interest rate on $440 million of long-term variable interest rate exposure that has not been hedged at January 1, 2007 was 5.50 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 $4.4 million at January 1, 2007. Subsequent to December 31, 2006, interest rate swaps hedging approximately $536 million of floating rate pollution control bonds matured, increasing the Company's variable rate exposure by $536 million. As a result, the effect of a 100 basis point change in interest rates for all currently unhedged variable rate long-term debt increased to approximately $9.8 million. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases. The Company has implemented fuel hedging programs at the instruction of the Alabama PSC.

In addition, the Company's Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75 percent of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5 percent of the Company's natural gas budget for that year.

At December 31, 2006, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. 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 thousands)	
Contracts beginning of year	**$ 28,978**	$ 4,017
Contracts realized or settled	**45,031**	(38,320)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**(106,637)**	63,281
Contracts end of year	**$ (32,628)**	$ 28,978

(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	2007	2008-2009
	(in thousands)		
Actively quoted	**$(33,304)**	**$(30,776)**	**$(2,528)**
External sources	**676**	**676**	**-**
Models and other methods	**-**	**-**	**-**
Contracts end of year	**$(32,628)**	**$(30,100)**	**$(2,528)**

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 clause. 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 thousands)
Regulatory assets, net	**$(33,267)**
Accumulated other comprehensive income	**676**
Net income	**(37)**
Total fair value	**$(32,628)**

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative 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 $1.2 billion for 2007, $1.3 billion for 2008, and $1.3 billion for 2009. Environmental expenditures included in these amounts are $505 million, $533 million, and $549 million for 2007, 2008, and 2009, respectively (including $202 million on selective catalytic reduction facilities and $1.2 billion on scrubbers, which reduce SO_2 emissions). In addition, over the next three years, the Company estimates spending $317 million on Plant Farley (including $211 million for nuclear fuel), $941 million on distribution facilities, and $405 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and 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 NRC requirements, the Company and Georgia Power have external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition to the funds required for the Company's construction program, approximately $1.3 billion will be required by the end of 2009 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower-cost capital if market conditions permit.

As discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the U.S. Department of Energy implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The final installment occurred in 2006.

The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over a long period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. For additional information, see Note 2 to the financial statements under "Postretirement Benefits."

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

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[a] --					
Principal	$ 669	$ 660	$ 300	$3,191	$ 4,820
Interest	249	413	365	3,315	4,342
Other derivative obligations[b] --					
Commodity	33	3	-	-	36
Interest	4	-	-	-	4
Preferred and preference stock dividends(c)	33	65	65	-	163
Operating leases	28	48	25	26	127
Purchase commitments[d]--					
Capital[e]	1,191	2,618	-	-	3,809
Coal	1,094	1,301	1,147	2,145	5,687
Nuclear fuel	26	69	84	67	246
Natural gas[f]	342	454	99	123	1,018
Purchased power	88	179	37	-	304
Long-term service agreements	17	35	36	67	155
Postretirement benefits[g]	25	47	-	-	72
Total	$3,799	$5,892	$2,158	$8,934	$20,783

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

(c) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2006, 2005, and 2004 were $1.10 billion, $1.04 billion, and $947 million, 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) 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 and retail rates, storm damage cost recovery and repairs, fuel cost recovery, environmental regulations and expenditures, earnings growth, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, completion of construction projects, impacts of adoption of new accounting rules, 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 actions relating to fuel and storm restoration 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
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$3,995,731**	$3,621,421	$3,292,828
Sales for resale --			
Non-affiliates	**634,552**	551,408	483,839
Affiliates	**216,028**	288,956	308,312
Other revenues	**168,417**	186,039	151,012
Total operating revenues	**5,014,728**	4,647,824	4,235,991
Operating Expenses:			
Fuel	**1,672,831**	1,457,301	1,186,472
Purchased power --			
Non-affiliates	**124,022**	188,733	186,187
Affiliates	**302,045**	268,751	226,697
Other operations	**720,296**	682,308	634,030
Maintenance	**376,682**	361,832	313,407
Depreciation and amortization	**451,018**	426,506	425,906
Taxes other than income taxes	**258,135**	248,854	242,809
Total operating expenses	**3,905,029**	3,634,285	3,215,508
Operating Income	**1,109,699**	1,013,539	1,020,483
Other Income and (Expense):			
Allowance for equity funds used during construction	**18,253**	20,281	16,141
Interest income	**20,897**	17,144	15,677
Interest expense, net of amounts capitalized	**(236,045)**	(197,367)	(193,590)
Interest expense to affiliate trusts	**(16,237)**	(16,237)	(16,191)
Other income (expense), net	**(23,758)**	(20,461)	(24,728)
Total other income and (expense)	**(236,890)**	(196,640)	(202,691)
Earnings Before Income Taxes	**872,809**	816,899	817,792
Income taxes	**330,345**	284,715	313,024
Net Income	**542,464**	532,184	504,768
Dividends on Preferred and Preference Stock	**24,734**	24,289	23,597
Net Income After Dividends on Preferred and Preference Stock	**$ 517,730**	$ 507,895	$ 481,171

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
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 542,464**	$ 532,184	$ 504,768
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	**524,313**	498,914	497,010
Deferred income taxes and investment tax credits, net	**(27,562)**	106,765	252,858
Deferred revenues	**(1,274)**	(12,502)	(11,510)
Allowance for equity funds used during construction	**(18,253)**	(20,281)	(16,141)
Pension, postretirement, and other employee benefits	**(15,196)**	(22,117)	(31,184)
Stock option expense	**4,848**	-	-
Tax benefit of stock options	**610**	17,400	10,672
Hedge settlements	**18,006**	(21,445)	2,241
Storm damage accounting order	**-**	48,000	-
Other, net	**12,832**	(15,491)	26,826
Changes in certain current assets and liabilities --			
Receivables	**(33,260)**	(255,481)	(126,432)
Fossil fuel stock	**(28,179)**	(44,632)	30,130
Materials and supplies	**(25,711)**	(16,935)	(26,229)
Other current assets	**38,645**	1,199	7,438
Accounts payable	**(49,725)**	80,951	(31,899)
Accrued taxes	**1,124**	(5,381)	(24,568)
Accrued compensation	**(6,157)**	3,273	(7,041)
Other current liabilities	**18,486**	33,675	(42,544)
Net cash provided from operating activities	**956,011**	908,096	1,014,395
Investing Activities:			
Property additions	**(933,306)**	(860,807)	(768,334)
Nuclear decommissioning trust fund purchases	**(286,551)**	(224,716)	(269,277)
Nuclear decommissioning trust fund sales	**285,685**	223,850	248,992
Cost of removal net of salvage	**(40,834)**	(61,314)	(37,369)
Other	**(1,777)**	(9,738)	(5,008)
Net cash used for investing activities	**(976,783)**	(932,725)	(830,996)
Financing Activities:			
Increase (decrease) in notes payable, net	**(195,609)**	315,278	-
Proceeds --			
Senior notes	**950,000**	250,000	900,000
Preferred and preference stock	**150,000**	-	100,000
Common stock issued to parent	**120,000**	40,000	40,000
Capital contributions	**27,160**	22,473	17,541
Gross excess tax benefit of stock options	**1,291**	-	-
Pollution control bonds	**-**	21,450	-
Redemptions --			
Senior notes	**(546,500)**	(225,000)	(725,000)
Pollution control bonds	**(2,950)**	(21,450)	-
Capital leases	**-**	(5)	(1,445)
Payment of preferred and preference stock dividends	**(24,318)**	(22,759)	(23,639)
Payment of common stock dividends	**(440,600)**	(409,900)	(437,300)
Other	**(24,635)**	(2,697)	(16,597)
Net cash provided from (used for) financing activities	**13,839**	(32,610)	(146,440)
Net Change in Cash and Cash Equivalents	**(6,933)**	(57,239)	36,959
Cash and Cash Equivalents at Beginning of Year	**22,472**	79,711	42,752
Cash and Cash Equivalents at End of Year	**$ 15,539**	$ 22,472	$ 79,711
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $7,930, $8,161, and $6,832 capitalized, respectively)	**$ 245,387**	$ 179,658	$ 188,556
Income taxes (net of refunds)	**345,803**	159,600	69,068

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

BALANCE SHEETS
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 15,539	$ 22,472
Receivables --		
Customer accounts receivable	323,202	275,702
Unbilled revenues	90,596	95,039
Under recovered regulatory clause revenues	32,451	132,139
Other accounts and notes receivable	49,708	50,008
Affiliated companies	70,836	77,304
Accumulated provision for uncollectible accounts	(7,091)	(7,560)
Fossil fuel stock, at average cost	153,120	102,420
Vacation pay	46,465	44,893
Materials and supplies, at average cost	255,664	244,417
Prepaid expenses	76,265	58,845
Other	66,663	98,506
Total current assets	1,173,418	1,194,185
Property, Plant, and Equipment:		
In service	15,997,793	15,300,346
Less accumulated provision for depreciation	5,636,475	5,313,731
	10,361,318	9,986,615
Nuclear fuel, at amortized cost	137,300	127,199
Construction work in progress	562,119	469,018
Total property, plant, and equipment	11,060,737	10,582,832
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	47,486	46,913
Nuclear decommissioning trusts, at fair value	513,521	466,963
Other	35,980	41,457
Total other property and investments	596,987	555,333
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	354,225	388,634
Prepaid pension costs	722,287	515,281
Deferred under recovered regulatory clause revenues	301,048	186,864
Other regulatory assets	279,661	122,378
Other	166,927	144,400
Total deferred charges and other assets	1,824,148	1,357,557
Total Assets	$14,655,290	$13,689,907

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

BALANCE SHEETS
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 668,646**	$ 546,645
Notes payable	**119,670**	315,278
Accounts payable --		
Affiliated	**162,951**	190,744
Other	**263,506**	266,174
Customer deposits	**62,978**	56,709
Accrued taxes --		
Income taxes	**3,120**	63,844
Other	**29,696**	31,692
Accrued interest	**53,573**	46,018
Accrued vacation pay	**38,767**	37,646
Accrued compensation	**87,194**	92,784
Other	**79,907**	72,991
Total current liabilities	**1,570,008**	1,720,525
Long-term Debt (See accompanying statements)	**3,838,906**	3,560,186
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	**309,279**	309,279
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,116,575**	2,070,746
Deferred credits related to income taxes	**98,941**	101,678
Accumulated deferred investment tax credits	**188,582**	196,585
Employee benefit obligations	**375,940**	208,663
Asset retirement obligations	**476,460**	446,268
Other cost of removal obligations	**600,278**	600,104
Other regulatory liabilities	**399,822**	194,135
Other	**35,805**	23,966
Total deferred credits and other liabilities	**4,292,403**	3,842,145
Total Liabilities	**10,010,596**	9,432,135
Preferred and Preference Stock (See accompanying statements)	**612,407**	465,046
Common Stockholder's Equity (See accompanying statements)	**4,032,287**	3,792,726
Total Liabilities and Stockholder's Equity	**$14,655,290**	$13,689,907
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
Alabama Power Company 2006 Annual Report

	2006	2005	**2006**	2005
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
2.65% to 2.80% due 2006	**$ -**	$ 520,000		
Floating rate (2.11% at 1/1/06) due 2006	**-**	26,500		
3.50% to 7.125% due 2007	**500,000**	500,000		
Floating rate (5.624% at 1/1/07) due 2007	**168,500**	168,500		
3.125% to 5.375% due 2008	**410,000**	410,000		
Floating rate (5.55% at 1/1/07) due 2009	**250,000**	250,000		
4.70% due 2010	**100,000**	100,000		
5.10% due 2011	**200,000**	-		
5.125% to 6.375% due 2016-2046	**2,325,000**	1,575,000		
Total long-term notes payable	**$3,953,500**	$ 3,550,000		
Other long-term debt --				
Pollution control revenue bonds --				
Variable rates (2.01% to 2.16% at 1/1/06) due 2015-2017	**-**	89,800		
5.50% due 2024	**-**	2,950		
Variable rates (3.91% to 4.07% at 1/1/07) due 2015-2031	**557,190**	467,390		
Total other long-term debt	**557,190**	560,140		
Capitalized lease obligations	**377**	564		
Unamortized debt premium (discount), net	**(3,515)**	(3,873)		
Total long-term debt (annual interest requirement -- $232.9 million)	**4,507,552**	4,106,831		
Less amount due within one year	**668,646**	546,645		
Long-term debt excluding amount due within one year	**$3,838,906**	$ 3,560,186	**43.6%**	43.8%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-term Debt Payable to Affiliated Trusts:				
4.75% to 5.5% due 2042				
(annual interest requirement -- $16.2 million)	**309,279**	309,279	**3.5**	3.8
Preferred and Preference Stock:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**47,610**	47,610		
$1 par value -- 4.95% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value	**294,105**	294,105		
Outstanding - 1,250 shares: $100,000 stated value	**123,331**	123,331		
Preference stock				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63%				
- 6,000,000 shares				
(non-cumulative) $25 stated value	**147,361**	-		
Total preferred and preference stock (annual dividend requirement -- $32.7 million)	**612,407**	465,046	**7.0**	5.7
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 2006: 25,000,000 shares				
- 2005: 15,000,000 shares				
Outstanding - 2006: 12,250,000 shares	**490,000**	370,000		
- 2005: 9,250,000 shares				
Paid-in capital	**2,028,963**	1,995,056		
Retained earnings	**1,516,245**	1,439,144		
Accumulated other comprehensive income (loss)	**(2,921)**	(11,474)		
Total common stockholder's equity	**4,032,287**	3,792,726	**45.9**	46.7
Total Capitalization	**$8,792,879**	$ 8,127,237	**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
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	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$290,000	$1,927,069	$1,291,558	$ (7,967)	$3,500,660
Net income after dividends on preferred stock	-	-	481,171	-	481,171
Issuance of common stock	40,000	-	-	-	40,000
Capital contributions from parent company	-	28,213	-	-	28,213
Other comprehensive income (loss)	-	-	-	(8,061)	(8,061)
Cash dividends on common stock	-	-	(437,300)	-	(437,300)
Other	-	(99)	5,620	-	5,521
Balance at December 31, 2004	330,000	1,955,183	1,341,049	(16,028)	3,610,204
Net income after dividends on preferred stock	-	-	507,895	-	507,895
Issuance of common stock	40,000	-	-	-	40,000
Capital contributions from parent company	-	39,873	-	-	39,873
Other comprehensive income (loss)	-	-	-	4,554	4,554
Cash dividends on common stock	-	-	(409,900)	-	(409,900)
Other	-	-	100	-	100
Balance at December 31, 2005	**370,000**	**1,995,056**	**1,439,144**	**(11,474)**	**3,792,726**
Net income after dividends on preferred and preference stock	-	-	**517,730**	-	**517,730**
Issuance of common stock	**120,000**	-	-	-	**120,000**
Capital contributions from parent company	-	**33,907**	-	-	**33,907**
Other comprehensive income (loss)	-	-	-	**(4,057)**	**(4,057)**
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	**12,610**	**12,610**
Cash dividends on common stock	-	-	**(440,600)**	-	**(440,600)**
Other	-	-	**(29)**	-	**(29)**
Balance at December 31, 2006	**$490,000**	**$2,028,963**	**$1,516,245**	**$ (2,921)**	**$4,032,287**

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
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred and preference stock	**$ 517,730**	$ 507,895	$ 481,171
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $1,109, $(1,422) and $(2,482), respectively	**1,768**	(2,338)	(4,083)
Change in fair value of marketable securities, net of tax of $-, $- and $252, respectively	-	-	414
Changes in fair value of qualifying hedges, net of tax of $155, $5,523 and $(4,807), respectively	**255**	9,085	(7,906)
Less: Reclassification adjustment for amounts included in net income, net of tax of $(3,696), $(1,333) and $2,136, respectively	**(6,080)**	(2,193)	3,514
Total other comprehensive income (loss)	**(4,057)**	4,554	(8,061)
Comprehensive Income	**$ 513,673**	$ 512,449	$ 473,110

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama 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 – the Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company -- are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electricity to retail customers within its traditional service area located within the State of Alabama 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, including the Company's Plant Farley. 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.

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 current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama 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 transactions. Costs for these services amounted to $266 million, $246 million, and $224 million during 2006, 2005, and 2004, respectively. 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 Southern Nuclear operates the Company's Plant Farley and provides the following nuclear-related services at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, statistical analysis, employee relations, and other services with respect to business and operations. Costs for these services amounted to $162 million, $157 million, and $169 million during 2006, 2005, and 2004, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of expenses which were $8.6 million in 2006, $8.2 million in 2005, and $7.2 million in 2004. See Note 4 for additional information.

Southern Company held a 30 percent ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel, until July 2006, when the ownership interest was terminated. The Company purchases synthetic fuel from AFP for use at several of the Company's plants. Total fuel purchases through June 2006 and for the years ended 2005 and 2004 were $202.2 million, $265.7 million, and $236.9 million, respectively. Subsequent to the termination of the membership interest in AFP, the Company continued to purchase fuel from AFP in the amount of $244.4 million in 2006. In addition, 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 $56.5 million, $31.5 million, and $28.7 million in 2006, 2005, and 2004, respectively.

In June 2003, the Company entered into an agreement with Southern Power under which the Company operates and maintains Plant Harris at cost. In 2006, 2005, and 2004, the Company billed Southern Power $2.2 million, $1.9 million, and $1.8 million, respectively, for operation and maintenance. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2006, 2005, and 2004 totaled $61.7 million, $63.6 million, and $59.0 million, respectively. The Company also provides the fuel, at cost, associated with the PPA and the fuel cost recognized by the Company was $77.8 million in 2006, $81.3 million in 2005, and $65.7 million in 2004. Additionally, the Company recorded $8.3 million of prepaid capacity expenses included in other deferred charges and other assets in the balance sheets at December 31, 2006 and 2005. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with SouthernLINC Wireless to provide digital wireless communications services to the Company. Costs for these services amounted to $4.9 million, $5.7 million, and $5.3 million during 2006, 2005, and 2004, respectively.

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 Company provides incidental services to, and receives such services from, other Southern Company subsidiaries which are generally minor in duration and/or amount. However, with the hurricane damage experienced by Georgia Power, Gulf Power and Mississippi Power in 2004 and 2005, assistance provided to aid in storm restoration, including Company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm restoration provided to Georgia Power and Gulf Power in 2004 and to Mississippi Power in 2005 was $2.4 million, $2.3 million, and $8.0 million, respectively. In 2004 and 2005, the Company received assistance from affiliated companies in the amount of $5.6 million and $5.0 million, respectively, for aid in major storm restoration. These activities were billed at cost.

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

Revenues

Energy and other revenues are recognized as services are provided. Capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate depending on the rate. See "Retail Regulatory Matters – Fuel Cost Recovery" in Note 3 for additional information.

The Company has a diversified base of customers. No single customer comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged less than one percent of revenues.

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 balance sheets at December 31 relate to:

	2006	2005	Note
	(in millions)		
Deferred income tax charges	**$ 354**	$ 389	(a)
Loss on reacquired debt	**94**	102	(b)
DOE assessments	**-**	5	(c)
Vacation pay	**46**	45	(d)
Under recovered regulatory clause revenues	**334**	319	(e)
Fuel-hedging assets	**36**	9	(f)
Other assets	**6**	6	(e)
Asset retirement obligations	**(152)**	(139)	(a)
Other cost of removal obligations	**(600)**	(600)	(a)
Deferred income tax credits	**(99)**	(102)	(a)
Natural disaster reserve (prior storms)	**17**	51	(e)
Fuel-hedging liabilities	**(3)**	(38)	(f)
Mine reclamation and remediation	**(16)**	(16)	(e)
Nuclear outage	**(12)**	(8)	(e)
Deferred purchased power	**(19)**	(19)	(e)
Natural disaster reserve (future storms)	**(13)**	-	(e)
Other liabilities	**(3)**	(3)	(e)
Overfunded retiree benefit plans	**(183)**	-	(g)
Underfunded retiree benefit plans	**183**	-	(g)
Total	**$ (30)**	$ 1	

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 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

(e) Recorded and recovered or amortized as approved or accepted by the Alabama PSC.

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

(g) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under "Retirement Benefits."

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 values. All regulatory assets and liabilities are to be reflected in rates.

Nuclear Fuel Disposal Costs

The Company has a contract with the U.S. Department of Energy (DOE) that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract. An on-site dry spent fuel storage facility at Plant Farley 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.

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 totaled $66 million in 2006, $64 million in 2005, and $61 million in 2004.

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 life 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.

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	**$ 8,312**	$ 7,971
Transmission	**2,308**	2,205
Distribution	**4,352**	4,115
General	**1,017**	1,000
Plant acquisition adjustment	**9**	9
Total plant in service	**$15,998**	$15,300

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 nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. The Company accrues estimated nuclear refueling costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2006, the Company accrued $31.5 million and paid $26.7 million for an outage at Unit 1. At December 31, 2006, the reserve balance totaled $12.3 million and is included in the balance sheet in other regulatory liabilities.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1 percent in 2006, 2.9 percent in 2005, and 3.0 percent in 2004. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

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 of 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 and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the Alabama 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 facility, Plant Farley. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2006 was $513 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of $35 million, related to asbestos removal and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" for further information on amounts included in rates.

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

	2006	2005
	(in millions)	
Balance beginning of year	**$446**	$384
Liabilities incurred	**3**	36
Liabilities settled	**(3)**	-
Accretion	**30**	26
Cash flow revisions	**-**	-
Balance end of year	**$476**	$446

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 the Alabama PSC, 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	**$ 121.0**	**$ (5.3)**	**$ 384.8**
Debt	**0.7**	**(1.4)**	**120.1**
Other	**-**	**-**	**8.6**
Total	**$ 121.7**	**$ (6.7)**	**$ 513.5**

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$ 78.9	$ (7.7)	$ 275.3
Debt	1.3	(1.6)	106.1
Other	17.0	-	85.6
Total	$ 97.2	$ (9.3)	$ 467.0

The contractual maturities of debt securities at December 31, 2006 are as follows: $1.2 million in 2007; $29.5 million in 2008-2011; $43.2 million in 2012-2016; and $45.1 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $285.7 million, $223.8 million, and $249.0 million in 2006, 2005, and 2004, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were $22.0 million and $18.2 million, respectively, in 2006. Net realized gains were $9.9 million and $7.5 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 flow.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama 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 designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. At December 31, 2006, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds, at fair value	$ 513
Internal reserves	28
Total	$ 541

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning, based on the most current study performed in 2003 for Plant Farley were as follows:

Decommissioning periods:	
Beginning year	2017
Completion year	2046
	(in millions)
Site study costs:	
Radiated structures	$ 892
Non-radiated structures	63
Total	$ 955

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.

All of the Company's decommissioning costs for ratemaking are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5 percent and a trust earnings rate of 7.0 percent. Another significant assumption used was the change in the operating license for Plant Farley.

In May 2005, the NRC granted the Company a 20-year extension of the operating license for both units at Plant Farley. As a result of the license extension, amounts previously contributed to the external trust are currently projected to be adequate to meet the decommissioning obligations. Therefore, in June 2005, the Alabama PSC approved the Company's request to suspend, effective January 1, 2005, the inclusion in its annual cost of service of $18 million in decommissioning costs and to also suspend the associated obligation to make semi-annual contributions to the external trust. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements. The approved suspension does not affect the transfer of internal reserves (less than $1 million annually) previously collected from customers prior to the establishment of the external trust.

Allowance for Funds Used During Construction (AFUDC)

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. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 8.8 percent in 2006, 8.8 percent in 2005, and 8.6 percent in 2004. AFUDC, net of income tax, as a percent of net income after dividends on preferred stock was 4.5 percent in 2006, 5.0 percent in 2005, and 4.2 percent in 2004.

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.

Natural Disaster Reserve

In accordance with an Alabama PSC order, the Company has established a natural disaster reserve (NDR) to cover the cost of uninsured damages from major storms to transmission and distribution facilities. The Company collects a monthly NDR charge per account that consists of two components which began on January 1, 2006. The first component is intended to establish and maintain a reserve for future storms and is an on-going part of customer billing. This plan has a target reserve balance of $75 million that could be achieved in five years assuming the Company experiences no additional storms. The second component of the NDR charge is intended to allow recovery of the deferred Hurricanes Dennis- and Katrina-related operations and maintenance costs and to set in place a mechanism to replenish the NDR should any future storms deplete the natural disaster reserve. The Alabama PSC order gives the Company authority to have a negative NDR balance when costs of uninsured storm damage exceed any established NDR balance. This second component allows for the recovery of a negative balance over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per account for non-residential customers and $5 per month per account for residential customers.

At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." Also the Company has recovered $33.8 million of deferred Hurricanes Dennis- and Katrina-related operations and maintenance costs and the deficit balance in the NDR account as of December 31, 2006 totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm-related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of the NDR charge.

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

Environmental Cost Recovery

The Company has received authority from the Alabama PSC to recover approved environmental compliance costs through specific retail rate clauses and are adjusted annually. See Note 3 under "Retail Regulatory Matters – Rate CNP" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, and natural gas. 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 Alabama 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 at January 1, 2006, for which the requisite service has 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 $4.8 million and $3.0 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises 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 $1.3 million.

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

Net Income	As Reported	Options Impact After Tax	Pro Forma
		(in thousands)	
2005	$507,895	$(2,829)	$505,066
2004	481,171	(2,575)	478,596

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 Alabama 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 other financial instruments for which the carrying amount did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2006	**$4,816**	**$4,768**
2005	4,416	4,403

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair 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. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information. 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.

Investments

The Company maintains an investment in a debt security that matures in 2018 and is classified as available-for-sale. This security is included in the balance sheets under Other Property and Investments-Other and totaled $2.6 million and $4.4 million at December 31, 2006 and 2005, respectively. Because the interest rate resets weekly, the carrying value approximates the fair market value.

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 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 trusts to the extent required by the Alabama PSC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $24.7 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 its underfunded non-qualified pension plan, the Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

With the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet previously unrecognized 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 as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $183 million with respect to its overfunded defined benefit plan and additional liabilities of $10 million and $147 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	$ 539	$ 183	$ 722
Other regulatory assets	97	183	280
Other property and investments	603	(6)	597
Total assets	14,295	360	14,655
Accumulated deferred income taxes	(2,110)	(7)	(2,117)
Other regulatory liabilities	(217)	(183)	(400)
Employee benefit obligations	(219)	(157)	(376)
Total liabilities	(9,664)	(347)	(10,011)
Accumulated other comprehensive income	16	(13)	3
Total shareholders' equity	(4,631)	(13)	(4,644)

Because the recovery of postretirement benefit expense through rates is considered probable, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71 with respect to the prepaid assets and the liabilities.

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 accumulated benefit obligation for the pension plans was $1.3 billion in 2006 and $1.3 billion in 2005. Changes during the year in the projected benefit obligations and fair value of plan assets were as follows:

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,421**	$ 1,325
Service cost	**37**	33
Interest cost	**76**	74
Benefits paid	**(69)**	(65)
Plan amendments	**2**	8
Actuarial (gain) loss	**(73)**	46
Balance at end of year	**1,394**	1,421
Change in plan assets		
Fair value of plan assets at beginning of year	**1,875**	1,676
Actual return on plan assets	**232**	262
Employer contributions	**4**	4
Benefits paid	**(69)**	(65)
Employee transfers	**(4)**	(2)
Fair value of plan assets at end of year	**2,038**	1,875
Funded status at end of year	**644**	454
Unrecognized prior service cost	**-**	79
Unrecognized net (gain)	**-**	(54)
Fourth quarter contributions	**1**	2
Prepaid pension asset, net	**$ 645**	$ 481

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $1.3 billion and $79 million, respectively. All plan assets are related to the qualified pension 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:

	2006	2005
	(in millions)	
Prepaid pension asset	**$ 722**	$ 515
Other regulatory assets	**36**	-
Current liabilities, other	**(5)**	-
Other regulatory liabilities	**(183)**	-
Employee benefit obligations	**(72)**	(67)
Other property and investments	**-**	10
Accumulated other comprehensive income	**-**	23

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
	(in millions)	
Balance at December 31, 2006:		
Regulatory asset	$ 6	$ 30
Regulatory liability	64	(247)
Total	$ 70	$ (217)
Estimated amortization in net periodic pension cost in 2007:		
Regulatory asset	$ 1	$ 3
Regulatory liability	8	-
Total	$ 9	$ 3

Components of net periodic pension cost (income) were as follows:

	2006	2005	2004
		(in millions)	
Service cost	**$ 37**	$ 33	$ 30
Interest cost	**77**	74	71
Expected return on plan assets	**(139)**	(139)	(138)
Recognized net (gain) loss	**3**	2	(3)
Net amortization	**9**	9	4
Net periodic pension (income)	**$ (13)**	$ (21)	$ (36)

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:

	Benefit Payments
	(in millions)
2007	$ 69
2008	71
2009	73
2010	77
2011	80
2012 to 2016	467

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		
Benefit obligation at beginning of year	**$ 490**	$ 465
Service cost	**7**	7
Interest cost	**26**	26
Benefits paid	**(22)**	(21)
Actuarial (gain) loss	**(13)**	13
Retiree drug subsidy	**2**	-
Balance at end of year	**490**	490
Change in plan assets		
Fair value of plan assets at beginning of year	**245**	212
Actual return on plan assets	**23**	28
Employer contributions	**27**	26
Benefits paid	**(36)**	(21)
Fair value of plan assets at end of year	**259**	245
Funded status at end of year	**(231)**	(245)
Unrecognized transition amount	**-**	29
Unrecognized prior service cost	**-**	64
Unrecognized net loss	**-**	85
Fourth quarter contributions	**26**	12
Accrued liability (recognized in the balance sheet)	**$ (205)**	$ (55)

Other postretirement benefit 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	45%	**46%**	53%
International equity	15	**16**	11
Fixed income	29	**28**	28
Real estate	7	**7**	6
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:

	2006	2005
	(in millions)	
Regulatory assets	**$ 147**	$ -
Employee benefit obligations	**(205)**	(55)

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 along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2006:			
Regulatory asset	$ 59	$ 63	$ 25
Estimated amortization as net periodic postretirement cost in 2007:			
Regulatory asset	$ 5	$ 2	$ 4

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

	2006	2005	2004
		(in millions)	
Service cost	**$ 7**	$ 7	$ 7
Interest cost	**26**	26	24
Expected return on plan assets	**(17)**	(16)	(18)
Net amortization	**12**	11	9
Net postretirement cost	**$ 28**	$ 28	$ 22

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 plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $3.2 million, $8.7 million, and $11.1 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	$ 23	$ (2)	$ 21
2008	25	(2)	23
2009	27	(3)	24
2010	30	(3)	27
2011	32	(4)	28
2012 to 2016	181	(26)	155

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 other 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	$ 36	$ 31
Service and interest costs	3	2

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 $14 million, $14 million, and $13 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 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 the Company, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company 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 five coal-fired generating facilities operated by the Company. 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 the Company and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required the Company 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 the Company, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company 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 the 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 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.

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 $3.9 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 $14.6 million for the Company, of which $3.1 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 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 the Company, Georgia Power, 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 two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11 million previously paid for interconnection facilities, with interest. The Company has also received requests for similar modifications from other entities totaling approximately $7 million, 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.

Retail Regulatory Matters

The following retail ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

Rate RSE

The Alabama PSC has adopted a Rate Stabilization and Equalization plan (Rate RSE) that provides for periodic annual adjustments based upon the Company's earned return on retail common equity. Prior to January 2007, annual adjustments were limited to 3 percent. Rates remain unchanged when the return on common equity ranges between 13.0 percent and 14.5 percent. On October 4, 2005, the Alabama PSC approved a revision to Rate RSE. Effective January 2007 and thereafter, Rate RSE adjustments are made based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0 percent per year and any annual adjustment is limited to 5.0 percent. The range of return on common equity, on which such adjustments are based, remains unchanged. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual return on common equity fall below the allowed equity return range. The Company made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007, effective in January, is 4.76 percent, or $193 million annually. Under the terms of Rate RSE, the maximum increase for 2008 cannot exceed 3.24 percent. See "Rate CNP" for additional information.

Rate CNP

The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the placing of new generating facilities in retail service and for the recovery of retail costs associated with certificated purchased power agreements (Rate CNP). In October 2004, the Alabama PSC approved a request by the Company to amend Rate CNP to provide for the recovery of retail costs associated with environmental laws and regulations. Environmental costs to be recovered include operation and maintenance expenses, depreciation and a return on invested capital. This component of Rate CNP began operation in January 2005.

To recover certificated purchased power costs under Rate CNP, increases of 0.8 percent in retail rates, or $25 million annually were effective July 2004. In April 2005, an adjustment to Rate CNP decreased retail rates by approximately 0.5 percent, or $19 million annually. In April 2006, an annual true-up adjustment to Rate CNP increased retail rates by approximately 0.5 percent, or $19 million annually.

The retail rates to recover retail costs associated with environmental laws and regulations under Rate CNP are adjusted annually in January. Retail rates increased approximately 1.0 percent in 2005, or $33 million. In 2006, retail rates increased approximately 1.2 percent, or $43 million, and in 2007 retail rates increased approximately 0.6 percent, or $23 million.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. The Company can change the retail energy cost recovery rate after submitting to the Alabama PSC an estimate of future energy costs and the current over or under recovered balance. In response to such a request, the Alabama PSC may conduct a public hearing prior to its ruling. Alternatively, the retail energy cost recovery rates requested by the Company will become effective 45 days after the initial request.

In December 2005, the Alabama PSC approved the Company's request to increase the retail energy cost recovery rate to 2.400 cents per kilowatt-hour, effective with billings that began in January 2006 for the 24-month period ending December 31, 2007. Thereafter, the energy cost recovery rate factor will increase absent a contrary order by the Alabama PSC.

The Company's under recovered fuel costs as of December 31, 2006 is $301.0 million and is classified as deferred charges and other assets in the balance sheet as of December 31, 2006.

Natural Disaster Cost Recovery

In September 2004, Hurricane Ivan hit the Gulf Coast of Florida and Alabama and continued north through the Company's service territory causing substantial damage. The related costs charged to the Company's NDR were $57.8 million. During 2004, the Company accrued $9.9 million to the reserve and at December 31, 2004, the reserve balance was a regulatory asset of $37.7 million.

In February and December 2005, the Company requested and received Alabama PSC approval of an accounting order that allowed the Company to immediately return certain regulatory liabilities to the retail customers. These orders also allowed the Company to simultaneously recover from customers an accrual of approximately $48 million primarily to offset the costs of Hurricane Ivan and restore a positive balance in the NDR. The combined effect of these orders had no impact on the Company's net income in 2005.

On July 10, 2005 and August 29, 2005, Hurricanes Dennis and Katrina, respectively, hit the coast of Alabama and continued north through the state, causing significant damage in parts of the service territory of the Company. Approximately 241,000 and 637,000 of the Company's 1.4 million customer accounts were without electrical service immediately after Hurricanes Dennis and Katrina, respectively. The Company sustained significant damage to its distribution and transmission facilities during these storms.

In August 2005, the Company received approval from the Alabama PSC to defer the Hurricane Dennis storm-related operation and maintenance costs (approximately $28 million). In October 2005, the Company also received similar approval from the Alabama PSC to defer the Hurricane Katrina storm-related operation and maintenance costs (approximately $30 million). The NDR balance at December 31, 2005 was a regulatory asset of $50.6 million.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted NDR and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components which began in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The Company currently expects that the target reserve balance could be achieved within five years. The second component of the NDR charge is intended to allow recovery of the existing deferred hurricane related operation and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

As of December 31, 2006, the Company had recovered $49.5 million of the costs allowed for storm-recovery activities and the deficit balance in the NDR account totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm-related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of NDR. At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities."

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia 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 these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense and a return on equity, 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 purchased power totaled $95 million in 2006, $90 million in 2005, and $86 million in 2004 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company 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. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2006, the capitalization of SEGCO consisted of $60 million of equity and $88 million of debt on which the annual interest requirement is $3.2 million. SEGCO paid dividends totaling $8.5 million in 2006, $7.7 million in 2005, and $12.0 million in 2004, of which one-half of each was paid to the Company. In addition, the Company recognizes 50 percent of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2006 is as follows:

Facility	Total Megawatt Capacity	Company Ownership
Greene County	**500**	**60.00% (1)**
Plant Miller		
Units 1 and 2	**1,320**	**91.84% (2)**

(1) Jointly owned with an affiliate, Mississippi Power.

(2) Jointly owned with Alabama Electric Cooperative, Inc.

Facility	Company Investment	Accumulated Depreciation
	(In millions)	
Greene County	**$ 118**	**$ 65**
Plant Miller		
Units 1 and 2	**958**	**396**

At December 31, 2006, the Company's Plant Miller portion of construction work in progress was $14.9 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in 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 State of Georgia and the State of Alabama. 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 and 2005, 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. At December 31, 2006 and 2005, the Company had $34.9 million and $20.4 million in accumulated deferred income taxes and $3.1 million and $2.0 million in accrued taxes -- income taxes, respectively, payable to these subsidiaries, on the balance sheets.

At December 31, 2006, the Company's tax-related regulatory assets and liabilities were $354 million and $99 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2006	2005	2004
		(in millions)	
Federal --			
Current	**$ 302**	$ 151	$ 44
Deferred	**(25)**	81	219
	277	232	263
State --			
Current	**56**	27	16
Deferred	**(3)**	26	34
	53	53	50
Total	**$ 330**	$ 285	$ 313

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	**$ 1,651**	$ 1,626
Property basis differences	**377**	426
Premium on reacquired debt	**39**	42
Pension and other benefits	**224**	148
Fuel clause under recovered	**137**	138
Regulatory assets associated with employee benefit obligations	**102**	-
Regulatory assets associated with asset retirement obligations	**200**	186
Storm reserve	**10**	26
Other	**57**	47
Total	**2,797**	2,639
Deferred tax assets:		
Federal effect of state deferred taxes	**118**	114
State effect of federal deferred taxes	**62**	87
Unbilled revenue	**25**	22
Pension and other benefits	**133**	20
Other comprehensive losses	**10**	19
Regulatory liabilities associated with employee benefit obligations	**71**	-
Asset retirement obligations	**200**	186
Other	**83**	56
Total	**702**	504
Total deferred tax liabilities, net	**2,095**	2,135
Portion included in current (liabilities) assets, net	**22**	(64)
Accumulated deferred income taxes in the balance sheets	**$ 2,117**	$ 2,071

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives 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 $8.0 million in 2006, $8.8 million in 2005, and $11.0 million in 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	**4.0**	4.2	4.0
Non-deductible book depreciation	**1.0**	1.1	1.1
Differences in prior years' deferred and current tax rates	**(0.3)**	(4.1)	(0.8)
Other	**(1.8)**	(1.3)	(1.0)
Effective income tax rate	**37.9%**	34.9%	38.3%

In accordance with Alabama PSC orders, the Company returned approximately $30 million of excess deferred income taxes to its ratepayers in 2005, resulting in 3.6 percent of the "Difference in prior years' deferred and current tax rates" in the table above. See Note 3 to the financial statements under "Retail Regulatory Matters – Natural Disaster Cost Recovery" for additional information.

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $309 million, which constitute substantially all 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 $300 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Pollution Control Bonds

Pollution control obligations represent installment purchases of pollution control facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds.

Senior Notes

The Company issued a total of $950 million of unsecured senior notes in 2006. The proceeds of these issuances were used to repay short-term indebtedness, and for other general corporate purposes.

At December 31, 2006 and 2005, the Company had $4.0 billion and $3.6 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2006.

On February 6, 2007, the Company issued $200 million of long-term senior notes. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Preference and Common Stock

In 2006, the Company issued six million new shares of preference stock at $25.00 stated capital per share and realized proceeds of $150 million. In addition, the Company issued three million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $120 million. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock outstanding. 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. Certain series of the preferred stock, Class A preferred stock, and preference stock are subject to redemption at the option of the Company on or after a specified date.

Securities Due Within One Year

At December 31, 2006 and 2005, the Company had scheduled maturities and redemptions of senior notes due within one year totaling $669 million and $547 million, respectively.

Debt maturities through 2011 applicable to total long-term debt are as follows: $669 million in 2007; $410 million in 2008; $250 million in 2009; $100 million in 2010; and $200 million in 2011.

Assets Subject to Lien

At January 1, 2006, the Company had a mortgage that secured first mortgage bonds they had issued and constituted a direct first lien on substantially all of its fixed property and franchises. In 2006, the Company discharged its remaining outstanding first mortgage bond obligations and the lien was removed in May 2006. The Company has granted liens on certain property in connection with the issuance of certain series of pollution control bonds with an outstanding principal amount of $153 million.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $965 million (including $563 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds), of which $365 million will expire at various times during 2007. $198 million of the credit facilities expiring in 2007 allow for the execution of one-year term loans. The remaining $600 million of credit facilities expire in 2011. All of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees are less than 1/4 of 1 percent for the Company. The Company does not consider any of its cash balances to be restricted as of any specific date.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65 percent of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2006, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through extendible commercial note programs and uncommitted credit arrangements. As of December 31, 2006, the Company had $120 million in commercial paper outstanding and no extendible commercial notes outstanding. As of December 31, 2005, the Company had $136 million in commercial paper outstanding, $55 million in extendible commercial notes outstanding, and $125 million in loans outstanding under an uncommitted credit arrangement. During 2006 and 2005, the peak amount outstanding for short-term borrowings was $411 million and $315 million, respectively. The average amount outstanding in 2006 and 2005 was $45 million and $31 million, respectively. The average annual interest rate on short-term borrowings in 2006 was 4.76 percent and in 2005 was 4.04 percent. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2006, the Company had regulatory approval to have outstanding up to $1.4 billion of short-term borrowings.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs at the instruction of the Alabama PSC. 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 thousands)
Regulatory assets, net	$ (33,267)
Accumulated other comprehensive income	676
Net income	(37)
Total fair value	$ (32,628)

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in the 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 also enters into derivatives to hedge exposure to changes in interest rates. 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.

At December 31, 2006, the Company had $736 million notional amount of interest rate derivatives outstanding with net fair value loss of $3.0 million as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/ (Loss)
		(in millions)	
2007***	2.01*	$ 536	$ 0.8
2017	6.15**	100	(1.9)
2017	6.15**	100	(1.9)

* Hedged using the Bond Market Association Municipal Swap Index.

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

*** Matured January 2007.

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) of $18.0 million, $(21.4) million, and $5.5 million, respectively, upon termination of certain interest derivatives at the same time it issued debt. These gains (losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative, which approximates to the related underlying debt.

For the years 2006, 2005, and 2004, approximately $9.8 million, $3.5 million, and $(6.3) million, respectively, of pre-tax gains (losses) were reclassified from other comprehensive income to interest expense. For 2007, pre-tax losses of approximately S0.1 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2017 and has gains (losses) that are being amortized through 2035.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $1.2 billion in 2007, $1.3 billion in 2008, and $1.3 billion in 2009. These amounts include $26 million, $35 million, and $34 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." The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; 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. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

The Company has entered into Long-Term Service Agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs provide 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, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $155 million over the remaining life of the agreements, which are currently estimated to range up to 10 years. However, the LTSAs contain various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2006 were as follows:

	Commitments		
Year	Affiliated	Non-Affiliated	Total
		(in millions)	
2007	$ 50	$ 38	$ 88
2008	50	39	89
2009	50	40	90
2010	12	23	35
2011	-	2	2
2012 and thereafter	-	-	-
Total commitments	$ 162	$ 142	$ 304

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 commitments at December 31, 2006 were as follows:

Year	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2007	$ 342	$ 1,094	$ 26
2008	281	683	35
2009	173	618	34
2010	84	603	39
2011	15	544	45
2012 and thereafter	123	2,145	67
Total commitments	$ 1,018	$ 5,687	$ 246

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 the Company 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.

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $30.3 million in 2006, $27.3 million in 2005, and $28.3 million in 2004. Of these amounts, $21.5 million, $17.8 million, and $16.3 million for 2006, 2005, and 2004, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR. At December 31, 2006, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Rail Cars	Vehicles & Other	Total
		(in millions)	
2007	$ 20.5	$ 7.6	$ 28.1
2008	19.7	6.4	26.1
2009	15.2	6.1	21.3
2010	10.4	5.7	16.1
2011	5.3	3.9	9.2
2012 and thereafter	22.9	3.0	25.9
Total minimum payments	$ 94.0	$ 32.7	$ 126.7

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2009 and 2010, and the Company's maximum obligations are $19.5 million and $62.3 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, 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 eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2006, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating 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 1,108 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 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 Dec. 31, 2005	5,227,985	$ 27.09
Granted	1,150,870	33.81
Exercised	(474,451)	24.28
Cancelled	(9,275)	29.35
Outstanding at Dec. 31, 2006	**5,895,129**	**$ 28.63**
Exercisable at Dec. 31, 2006	**3,739,865**	**$ 26.26**

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

As of December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.6 years and 5.5 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $48.5 million and $39.7 million, respectively.

As of December 31, 2006, there was $1.4 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 $4.9 million, $21.9 million, and $16.1 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.9 million, $8.5 million, and $6.2 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 Plant Farley. The Act provides funds up to $10.8 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $201 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 the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 $38 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 $3.2 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 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2006	**$ 1,073**	**$ 198**	**$ 82**
June 2006	**1,249**	**258**	**118**
September 2006	**1,572**	**458**	**238**
December 2006	**1,121**	**196**	**80**
March 2005	$ 970	$ 157	$ 93
June 2005	1,086	253	122
September 2005	1,458	443	236
December 2005	1,134	161	57

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

SELECTED FINANCIAL AND OPERATING DATA 2002-2006

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	$ **5,014,728**	$ 4,647,824	$ 4,235,991	$ 3,960,161	$ 3,710,533
Net Income after Dividends on Preferred and Preference Stock (in thousands)	$ **517,730**	$ 507,895	$ 481,171	$ 472,810	$ 461,355
Cash Dividends on Common Stock (in thousands)	$ **440,600**	$ 409,900	$ 437,300	$ 430,200	$ 431,000
Return on Average Common Equity (percent)	**13.23**	13.72	13.53	13.75	13.80
Total Assets (in thousands)	$ **14,655,290**	$ 13,689,907	$ 12,781,525	$ 12,099,575	$ 11,591,666
Gross Property Additions (in thousands)	$ **960,759**	$ 890,062	$ 786,298	$ 661,154	$ 645,262
Capitalization (in thousands) **:**					
Common stock equity	$ **4,032,287**	$ 3,792,726	$ 3,610,204	$ 3,500,660	$ 3,377,740
Preferred and preference stock	**612,407**	465,046	465,047	372,512	247,512
Mandatorily redeemable preferred securities	-	-	-	300,000	300,000
Long-term debt payable to affiliated trusts	**309,279**	309,279	309,279	-	-
Long-term debt	**3,838,906**	3,560,186	3,855,257	3,377,148	2,872,609
Total (excluding amounts due within one year)	$ **8,792,879**	$ 8,127,237	$ 8,239,787	$ 7,550,320	$ 6,797,861
Capitalization Ratios (percent) **:**					
Common stock equity	**45.9**	46.7	43.8	46.4	49.7
Preferred and preference stock	**7.0**	5.7	5.6	4.9	3.6
Mandatorily redeemable preferred securities	-	-	-	4.0	4.4
Long-term debt payable to affiliated trusts	**3.5**	3.8	3.8	-	-
Long-term debt	**43.6**	43.8	46.8	44.7	42.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	-	A1	A1	A1	A1
Standard and Poor's	-	A+	A	A	A
Fitch	-	AA-	AA-	A+	A+
Preferred Stock/Preference 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	**1,194,696**	1,184,406	1,170,814	1,160,129	1,148,645
Commercial	**214,723**	212,546	208,547	204,561	203,017
Industrial	**5,750**	5,492	5,260	5,032	4,874
Other	**766**	759	753	757	789
Total	**1,415,935**	1,403,203	1,385,374	1,370,479	1,357,325
Employees (year-end)	**6,796**	6,621	6,745	6,730	6,715

SELECTED FINANCIAL AND OPERATING DATA 2002-2006 (continued)

Alabama Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	**$ 1,664,304**	$ 1,476,211	$ 1,346,669	$ 1,276,800	$ 1,264,431
Commercial	**1,172,436**	1,062,341	980,771	913,697	882,669
Industrial	**1,140,225**	1,065,124	948,528	844,538	788,037
Other	**18,766**	17,745	16,860	16,428	16,080
Total retail	**3,995,731**	3,621,421	3,292,828	3,051,463	2,951,217
Sales for resale - non-affiliates	**634,552**	551,408	483,839	487,456	474,291
Sales for resale - affiliates	**216,028**	288,956	308,312	277,287	188,163
Total revenues from sales of electricity	**4,846,311**	4,461,785	4,084,979	3,816,206	3,613,671
Other revenues	**168,417**	186,039	151,012	143,955	96,862
Total	**$ 5,014,728**	$ 4,647,824	$ 4,235,991	$ 3,960,161	$ 3,710,533
Kilowatt-Hour Sales (in thousands):					
Residential	**18,632,935**	18,073,783	17,368,321	16,959,566	17,402,645
Commercial	**14,355,091**	14,061,650	13,822,926	13,451,757	13,362,631
Industrial	**23,187,328**	23,349,769	22,854,399	21,593,519	21,102,568
Other	**199,445**	198,715	198,253	203,178	205,346
Total retail	**56,374,799**	55,683,917	54,243,899	52,208,020	52,073,190
Sales for resale - non-affiliates	**15,978,465**	15,442,728	15,483,420	17,085,376	15,553,545
Sales for resale - affiliates	**5,145,107**	5,735,429	7,233,880	9,422,301	8,844,050
Total	**77,498,371**	76,862,074	76,961,199	78,715,697	76,470,785
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.93**	8.17	7.75	7.53	7.27
Commercial	**8.17**	7.55	7.10	6.79	6.61
Industrial	**4.92**	4.56	4.15	3.91	3.73
Total retail	**7.09**	6.50	6.07	5.84	5.67
Sales for resale	**4.03**	3.97	3.49	2.88	2.72
Total sales	**6.25**	5.80	5.31	4.85	4.73
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,663**	15,347	14,894	14,688	15,198
Residential Average Annual Revenue Per Customer	**$ 1,399**	$ 1,253	$ 1,155	$ 1,106	$ 1,104
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,216	12,216	12,174	12,153
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,309**	9,812	9,556	10,409	9,423
Summer	**11,744**	11,162	10,938	10,462	10,910
Annual Load Factor (percent)	**61.8**	63.2	63.2	64.1	62.9
Plant Availability (percent):					
Fossil-steam	**89.6**	90.5	87.8	85.9	85.8
Nuclear	**93.3**	92.9	88.7	94.7	93.2
Source of Energy Supply (percent) :					
Coal	**60.2**	59.5	56.5	56.5	55.5
Nuclear	**17.4**	17.2	16.4	17.0	17.1
Hydro	**3.8**	5.6	5.6	7.0	5.1
Gas	**7.6**	6.8	8.9	7.6	11.6
Purchased power -					
From non-affiliates	**2.1**	3.8	5.4	4.1	4.0
From affiliates	**8.9**	7.1	7.2	7.8	6.7
Total	**100.0**	100.0	100.0	100.0	100.0

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

David J. Cooper, Sr.
President,
Cooper/T. Smith Corporation

R. Kent Henslee[1]
Managing Partner,
Henslee, Robertson, Strawn & Knowles, L.L.C

John D. Johns
Chairman, President and CEO,
Protective Life Corporation

Carl E. Jones, Jr. [1]
Chairman,
Regions Financial Corporation

Patricia M. King
President and CEO,
Sunny King Automotive Group

James K. Lowder
Chairman,
The Colonial Company

Wallace D. Malone, Jr. [1]
Formally Vice Chairman,
Wachovia Corporation

Charles D. McCrary
President and CEO,
Alabama Power Company

Malcolm Portera
Chancellor, The University of Alabama System

Robert D. Powers
President, The Eufaula Agency

David M. Ratcliffe
Chairman, President and CEO,
Southern Company

C. Dowd Ritter
President and CEO,
Regions Financial Corporation

James H. Sanford
Chairman, HOME Place Farms, Inc.

John Cox Webb, IV
President, Webb Lumber Company, Inc.

James W. Wright
Chairman, President and CEO,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

Art P. Beattie
Executive Vice President, Chief Financial Officer and Treasurer

C. Alan Martin
Executive Vice President

Steve R. Spencer
Executive Vice President

Mark A. Crosswhite[2]
Senior Vice President and Counsel

Rodney O. Mundy[3]
Senior Vice President and Counsel

Robert Holmes, Jr.
Senior Vice President

Robin A. Hurst
Senior Vice President

Michael L. Scott
Senior Vice President

Jerry L. Stewart
Senior Vice President

Philip C. Raymond
Vice President and Comptroller

William E. Zales, Jr.
Vice President, Corporate Secretary and Assistant Treasurer

Greg Barker[4]
Vice President

Christopher T. Bell[5]
Vice President

Robert A. Bell
Vice President

Willard L. Bowers
Vice President

Leigh Davis[6]
Vice President

Larry R. Grill
Vice President

Donald R. Horsley[7]
Vice President

Gerald L. Johnson
Vice President, Birmingham Division

William B. Johnson
Vice President

Bobby J. Kerley[8]
Vice President

Barbara J. Knight
Vice President

Gordon G. Martin
Vice President, Southern Division

Myrna J. Pittman
Vice President

Donald W. Reese
Vice President

R. Michael Saxon
Vice President, Southeast Division

Julia H. Segars[9]
Vice President, Eastern Division

Julian H. Smith, Jr.
Vice President

W. Ronald Smith[10]
Vice President, Eastern Division

Zeke W. Smith
Vice President

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

Anita Allcorn-Walker[11]
Assistant Comptroller

Robert Cole Giddens[12]
Assistant Comptroller

Ronald Q. Patterson[11]
Assistant Comptroller

E. Wayne Boston
Assistant Secretary and Assistant Treasurer

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

J. Randy DeRieux
Assistant Treasurer

All information as of December 31, 2006 except as noted below

[1] Retired 4/06
[2] Elected 7/06
[3] Retired 7/06
[4] Elected 1/07
[5] Resigned 12/06
[6] Elected 6/06
[7] Resigned 3/06
[8] Elected 4/06
[9] Effective 4/06
[10] Retired 6/06
[11] Appointed 6/06
[12] Retired 6/06

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 operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.4 million customers within its service area of approximately 45,000 square miles. In 2006, retail energy sales accounted for 73 percent of the Company's total sales of 77 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies. 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 (as successor to
JPMorgan Chase Bank, N.A.)
Global Trust Administration
101 Barclay Street, 8W
New York, NY 10286

Registrar, Transfer Agent and Dividend Paying Agent
All series except the Flexible Money Market and 5.30% Series Class A Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

The Flexible Money Market and 5.30% Series
Class A Preferred Stock
The Bank of New York
101 Barclay Street
New York, NY 10286

Number of Preferred and Preference Shareholders of record as of December 31, 2006 was 1,641.

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (205) 257-3385.

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