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2007 Annual Report

ALABAMA POWER COMPANY

ALABAMA POWER

A SOUTHERN COMPANY

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SUMMARY

	2007	2006	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$5,360**	$5,015	6.9
Operating expenses	**$4,145**	$3,905	6.1
Net income after dividends on preferred and preference stock	**$580**	$518	11.9
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**56,642**	56,375	0.5
Sales for resale - non-affiliates	**15,769**	15,978	(1.3)
Sales for resale - affiliates	**3,241**	5,145	(37.0)
Total	**75,652**	77,498	(2.4)
Customers served at year-end *(in thousands)*	**1,431**	1,416	1.1
Peak-hour demand *(in megawatts)*	**12,211**	11,744	4.0
Capitalization Ratios *(percent)*:			
Common stock equity	**44.8**	45.9	
Preferred and preference stock	**6.9**	7.0	
Long-term debt (Excluding long-term debt due within one year)	**48.3**	47.1	
Return on Average Common Equity *(percent)*	**13.73**	13.23	

2007 Letter to Investors

Although Alabama Power faced extraordinary challenges in 2007, I am proud to report that we continued our tradition of keeping our commitments to our shareholders, our customers, and the communities we serve.

Thankfully, 2007 did not bring the devastating storms we've faced in recent years. However, Mother Nature tested us in other ways as Alabama experienced the worst drought in state history. As the largest water manager in the state, Alabama Power worked hard to ensure that the state's rivers remained safe for navigation, that municipalities had drinking water, and that businesses relying heavily on water from state rivers remained open.

Even with generation from our hydro plants down 66 percent due to the drought, we still met record demand during almost two weeks of 100-degree-plus weather in August. There were 12 days in August when we topped the previous year's peak demand before reaching an all-time peak of 12,211 megawatts on August 22, 2007.

We continued to see sharp increases in the price of fuel, steel, copper, and other materials that are essential to our business. Through the hard work of 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 2007. Because of our excellent transmission and distribution system, our reliability rate remained at 99.9 percent. Our fossil and hydro generating plants set a new record for reliability, and we again ranked in the top quartile in customer satisfaction among peer utilities across the nation.

We continued to install new equipment and technology to further reduce emissions of nitrogen oxide, sulfur dioxide, and mercury from our generating plants which helps to protect the environment.

While we're proud of our accomplishments in 2007, we know we can't focus on the past or solely on ourselves. Our industry is increasingly impacted by national and global issues and events, and you can be assured that Alabama Power is aware of, and prepared to meet, the challenges ahead.

At the same time, we will continue to live the philosophy that has guided Alabama Power for more than a century. We will continue to make every decision with the best interests of our customers, shareholders, and employees in mind.

I have every confidence this philosophy will lead to continued success in 2008 and beyond.

Sincerely,

Charles D. McCrary

Charles D. McCrary
President and Chief Executive Officer
March 20, 2008

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2007 Annual Report

The management of Alabama Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2007.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

Charles D. McCrary
President and Chief Executive Officer

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

February 25, 2008

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, 2007 and 2006, 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, 2007. 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 26 to 61) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

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

Deloitte & Touche LLP

Birmingham, Alabama
February 25, 2008

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, capital expenditures, and restoration following major storms. Appropriately balancing these required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Since 2005, the Company has completed a number of successful regulatory proceedings that provide for the timely recovery of costs. These 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 after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2007 Peak Season EFOR of 0.59% was better than the target. The nuclear generating fleet also uses Peak Season EFOR as an indicator of availability and efficient generation fleet operations during the peak season. The nuclear 2007 Peak Season EFOR of 0.20% was also better than the target. 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 2007 was better than target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary component of the Company's contribution to Southern Company's earnings per share goal. The Company's 2007 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2007 Target Performance	2007 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR – fossil/hydro	2.75% or less	0.59%
Peak Season EFOR – nuclear	2.00% or less	0.20%
Net Income	$548 million	$580 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2007 reflects the continued management emphasis, as well as the commitment shown by employees in achieving or exceeding these key performance expectations.

Earnings

The Company's financial performance remained strong in 2007 despite the challenges of rising costs. The Company's net income after dividends on preferred and preference stock of $580 million in 2007 increased $62 million (11.9%) over the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under Rate Stabilization and Equalization Plan (Rate RSE) and Rate Certificated New Plant (Rate CNP) for environmental costs that took effect January 1, 2007 as well as favorable weather conditions, partially offset by higher non-fuel operating expenses and increased interest expense.

The Company's 2006 net income after dividends on preferred and preference stock was $518 million, representing a $10 million (1.9%) increase from the prior year. This improvement was 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%) 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.

RESULTS OF OPERATIONS

A condensed income statement follows:

	Amount	Increase (Decrease) from Prior Year		
	2007	**2007**	2006	2005
		(in millions)		
Operating revenues	**$5,360**	**$345**	$367	$412
Fuel	**1,762**	**90**	216	271
Purchased power	**438**	**12**	(31)	44
Other operations and maintenance	**1,186**	**89**	53	97
Depreciation and amortization	**472**	**21**	24	1
Taxes other than income taxes	**287**	**28**	9	6
Total operating expenses	**4,145**	**240**	271	419
Operating income	**1,215**	**105**	96	(7)
Total other income and (expense)	**(248)**	**(11)**	(40)	6
Income taxes	**351**	**21**	46	(29)
Net income	**616**	**73**	10	28
Dividends on preferred and preference stock	**36**	**11**	-	1
Net income after dividends on preferred and preference stock	**$ 580**	**$ 62**	$ 10	$ 27

Operating Revenues

Operating revenues for 2007 were $5.4 billion, reflecting a $345 million increase from 2006. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2007	2006	2005
		(in millions)	
Retail – prior year	**$3,995.7**	$3,621.4	$3,292.8
Estimated change in –			
Rates and pricing	**216.3**	48.4	25.3
Sales growth	**(4.9)**	35.8	60.3
Weather	**37.6**	19.9	17.9
Fuel and other cost recovery	**162.3**	270.2	225.1
Retail – current year	**4,407.0**	3,995.7	3,621.4
Wholesale revenues –			
Non-affiliates	**627.0**	634.6	551.4
Affiliates	**144.1**	216.0	289.0
Total wholesale revenues	**771.1**	850.6	840.4
Other operating revenues	**181.9**	168.4	186.0
Total operating revenues	**$5,360.0**	$5,014.7	$4,647.8
Percent change	**6.9%**	7.9%	9.7%

Retail revenues in 2007 were $4.4 billion. These revenues increased $411 million (10.3%) in 2007, $374 million (10.3%) in 2006, and $329 million (10.0%) in 2005. These increases were primarily due to increased fuel revenue and base rate increases of 5.3% in January 2007, 2.6% in January 2006, and 1.0% in January 2005. 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.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2007	2006	2005
		(in millions)	
Unit power sales –			
Capacity	**$151**	$154	$148
Energy	**192**	198	169
Total	**343**	352	317
Other power sales –			
Capacity and other	**128**	137	116
Energy	**156**	146	118
Total	**284**	283	234
Total non-affiliated	**$627**	$635	$551

Wholesale revenues to non-affiliates include unit power sales under long-term contracts to Florida utilities and sales to wholesale customers within the Company's service territory. 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 energy sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. No significant declines in the amount of capacity revenues are scheduled until the termination of the unit power sales contracts in May 2010. Short-term opportunity energy sales are also included in wholesale energy sales 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.

Wholesale 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 2007, wholesale revenues from sales to affiliates decreased $71.9 million primarily due to a 37.0% 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 2006, wholesale revenues decreased $73.0 million primarily due to a 16.7% decrease in price and a 10.3% decrease in 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, wholesale revenues decreased $19.4 million primarily due to a 20.7% 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. 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 (Rate ECR).

Other operating revenues in 2007 increased $13.5 million (8.0%) from 2006 primarily due to a $4.0 million increase in revenues from electric property associated with pole attachment and building rentals, a $2.6 million increase in transmission revenues, and a $2.5 million increase in revenues from gas-fueled co-generation steam facilities. In 2006, other operating revenues decreased $17.6 million (9.5%) from 2005 primarily due to a decrease of $14.6 million in revenues from gas-fueled co-generation steam facilities mainly as a result of lower gas prices. In 2005, other operating revenues increased $35.0 million (23.2%) 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 affiliated companies primarily related to leased transmission facilities. 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 the volume of energy sold from year to year. KWH sales for 2007 and the percent change by year were as follows:

	KWHs	Percent Change		
	2007	**2007**	2006	2005
	(in billions)			
Residential	**18.9**	**1.3%**	3.1%	4.1%
Commercial	**14.8**	**2.8**	2.1	1.7
Industrial	**22.8**	**(1.6)**	(0.7)	2.2
Other	**0.2**	**0.7**	0.4	0.2
Total retail	**56.7**	**0.5**	1.2	2.7
Wholesale -				
Non-affiliates	**15.8**	**(1.3)**	3.5	(0.3)
Affiliates	**3.2**	**(37.0)**	(10.3)	(20.7)
Total wholesale	**19.0**	**(10.0)**	(0.3)	(6.8)
Total energy sales	**75.7**	**(2.4)**	0.8	(0.1)

Retail energy sales in 2007 were 0.5% higher than in 2006. Energy sales in the residential and commercial sectors led the growth with a 1.3% and a 2.8% increase, respectively, due primarily to weather-driven increased demand. Industrial sales decreased 1.6% during the year primarily as a result of decreased sales demand in textiles and food, primary metals, and chemical sectors.

Retail energy sales in 2006 were 1.2% higher than in 2005. Energy sales in the residential and commercial sectors led the growth with a 3.1% and a 2.1% increase, respectively, due primarily to weather-driven increased demand. Industrial sales decreased 0.7% 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% higher than 2004 despite interruptions during Hurricanes Dennis and Katrina. Energy sales in the residential sector led the growth with a 4.1% increase in 2005 due primarily to increased demand. Commercial sales increased 1.7% in 2005 primarily due to continued customer growth. Industrial sales increased 2.2% 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.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's electricity generated and purchased were as follows:

	2007	2006	2005
Total generation *(billions of KWHs)*	**69.8**	72.0	71.2
Total purchased power *(billions of KWHs)*	**9.6**	8.9	8.7
Sources of generation *(percent)* –			
Coal	**69**	68	67
Nuclear	**19**	19	19
Gas	**10**	9	8
Hydro	**2**	4	6
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**2.14**	2.09	1.85
Nuclear	**0.50**	0.47	0.46
Gas	**7.43**	7.87	7.43
Average cost of fuel, generated *(cents per net KWH)*	**2.36**	2.27	2.02
Average cost of purchased power *(cents per net KWH)*	**6.07**	5.98	6.49

Fuel and purchased power expenses were $2.2 billion in 2007, an increase of $101.9 million (4.9%) above the prior year costs. This increase was the result of a $70.3 million increase in the cost of fuel and a $31.6 million increase related to the volume of KWHs generated and purchased.

Fuel and purchased power expenses were $2.1 billion in 2006, an increase of $184.1 million (9.6%) 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 the volume of KWHs generated and purchased.

Fuel and purchased power expenses were $1.9 billion in 2005, an increase of $315.4 million (19.7%) 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 the volume of KWHs 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 $27.1 million (21.8%) in 2007 due to a 22.6% decrease in the amount of energy purchased. In 2006, purchased power from non-affiliates decreased $64.7 million (34.3%) due to a 26.8% decrease in the amount of energy purchased and a 10.3% decrease in purchased power prices over the previous year. In 2005, purchased power from non-affiliates increased $2.5 million (1.0%) due to a 14.3% increase in purchased power prices over the previous year.

While there has been a significant upward trend in the cost of coal and natural gas since 2003, prices moderated somewhat in 2006 and 2007. Coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. While demand for natural gas in the United States continued to increase in 2007, natural gas supplies have also risen due to increased production and higher storage levels. During 2007, uranium prices were volatile and increased over the course of the year due to increasing long-term demand with primary production levels at approximately 55% to 60% of demand. Secondary supplies and inventories were sufficient to fill the primary production shortfall.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's Rate ECR. The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. 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 Operations and Maintenance Expenses

In 2007, other operations and maintenance expenses increased $89.3 million (8.1%) primarily due to a $28.5 million increase in steam production expense related to environmental mandates and scheduled outage costs, a $19.6 million increase in transmission and distribution expense related to overhead line clearing costs, a $19.0 million increase in administrative and general expenses related to an increase in the expenses for the injuries and damages reserve, outside services, and employee benefits, an $8.1 million increase in nuclear production expense related to scheduled outage cost, a $4.7 million increase in customer accounts expense associated with customer service expenses, and a $9.4 million increase in miscellaneous other operations and maintenance expenses. In 2006, other operations and maintenance expenses increased $52.8 million (5.1%) 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, a $5.4 million increase in steam production expense related to environmental costs, and a $8.7 million increase in miscellaneous other operations and maintenance expenses. In 2005, other operations and maintenance expenses increased $96.7 million (10.2%). This increase was primarily due to an increase in transmission and distribution expense of $37.3 million as a result of the Alabama 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, administrative and general expenses increased $20.7 million related to employee benefits, and miscellaneous other operations and maintenance expenses increased $10.6 million.

Depreciation and Amortization

Depreciation and amortization expenses increased $20.5 million (4.5%) in 2007 primarily due to additions to property, plant, and equipment related to environmental mandates and distribution projects. In 2006, depreciation and amortization expenses increased $24.5 million (5.7%) primarily due to additions to property, plant, and equipment related to environmental and distribution projects. In 2005, depreciation and amortization expenses remained relatively flat compared to the prior year, increasing only $0.6 million (0.1%). During 2005, the depreciation rates used by the Company were adjusted based on a periodic external study 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.

Taxes Other than Income Taxes

Taxes other than income taxes increased $28.4 million (11.0%) in 2007, $9.3 million (3.7%) in 2006, and $6.0 million (2.5%) in 2005, primarily due to increases in state and municipal public utility license taxes which are directly related to the increase in retail revenues.

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) increased $17.2 million (94.1%) in 2007 primarily due to increases in the amount of construction work in progress related to environmental mandates at generating facilities and transmission and distribution projects compared to the prior year. AFUDC decreased $2.0 million (10.0%) in 2006 primarily due to the timing of construction expenditures compared to the prior year. AFUDC increased $4.1 million (25.6%) in 2005 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 Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $21.5 million (8.5%) in 2007 primarily due to higher interest rates on new issuance of long-term debt and higher interest rates on the Company's outstanding variable rate securities. Interest expense, net of amounts capitalized, increased $38.7 million (18.1%) 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%) in 2005 due to an increase in average debt outstanding during the year.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. Retail rates may be adjusted annually 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 or market-based prices, 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. Any adverse effect of inflation on the Company's results of operations has not been substantial. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition 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 wholesale electricity sales, 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 1.9% annually on average during 2008 through 2012.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to 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 statutes and regulations are adopted or 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.

In June 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. In August 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 all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, and the appeal was stayed by the Appeals Court pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007. On October 5, 2007, the U.S. District Court for the Northern District of Alabama issued an order in the Company's case indicating a willingness to re-evaluate its previous decision in light of the Supreme Court's Duke Energy opinion. On December 21, 2007, the Eleventh Circuit vacated the district court's decision in the Company's case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. The final outcome of these matters cannot be determined at this time.

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 or affect the timing of currently budgeted 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. In June 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. In March 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. The EPA has 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, and no decision has been issued. 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, which are expected to be recovered through existing ratemaking provisions. Through 2007, the Company had invested approximately $1.7 billion in capital projects to comply with these requirements, with annual totals of $469 million, $260 million, and $256 million for 2007, 2006, and 2005, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $646 million, $617 million, and $126 million for 2008, 2009, and 2010, respectively. The Company's compliance strategy is impacted by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. 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 2007, the Company had spent approximately $1.4 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.

In 2004, the EPA designated nonattainment areas under an 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 by the EPA in June 2006, and the EPA subsequently approved a maintenance plan for the area to address future exceedances of the standard. In December 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. On June 20, 2007, the EPA proposed additional revisions to the current eight-hour ozone standard which, if enacted, could result in designation of new nonattainment areas within the Company's service territory. The EPA has requested comment and is expected to publish final revisions to the standard in 2008. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or future nonattainment designations and state regulatory plans.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within the Company's service area. 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. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. In December 2007, state agencies recommended to the EPA that Jefferson County (Birmingham) and Etowah County (Gadsden) in Alabama be designated as nonattainment for this standard. The EPA plans to designate nonattainment areas based on the new standard by December 2009. The ultimate outcome of this matter depends on the development and submittal of the required state plans and resolution of pending legal challenges and, therefore, 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. The State of Alabama has an EPA-approved implementation plan for this rule. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities and/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 by 2018 toward the natural conditions goal. 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. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. States are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, and the Clean Air Visibility Rule on the Company will depend on the development and implementation of rules at the state level. 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 and NO_x emission controls within the next several years to assure continued compliance with applicable air quality requirements.

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 final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court vacated the Clean Air Mercury Rule. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NO_x controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings could require emission reductions more stringent than required by the Clean Air Mercury Rule.

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 of Alabama regulatory agencies and, therefore, cannot be determined at this time.

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

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions continue to be considered in Congress. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that could follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on July 13, 2007, the Governor of the State of Florida signed three executive orders addressing reduction of greenhouse gas emissions within the state, including statewide emission reduction targets beginning in 2017. Included in the orders is a directive to the Florida Secretary of Environmental Protection to develop rules adopting maximum allowable emissions levels of greenhouse gases for electric utilities, consistent with the statewide emission reduction targets, and a request to the Florida PSC to initiate rulemaking requiring utilities to produce at least 20% of their electricity from renewable sources. The impact of any similar state requirements on the Company will depend on the future development, adoption, and implementation of state laws or rules governing greenhouse gas emissions, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2008 through 2012 timeframe. The outcome and impact of the international negotiations cannot be determined at this time.

The Company continues to evaluate its future energy and emission profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

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 the 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 that ended in May 2006 could be subject to refund to a cost-based rate level.

In late June and July 2007, hearings were held in this proceeding and the presiding administrative law judge issued an initial decision on November 9, 2007 regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company 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, and could also result in refunds of up to $3.9 million, plus interest. The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter.

On June 21, 2007, the FERC issued its final rule regarding market-based rate authority. The FERC generally retained its current market-based rate standards. The impact of this order and its effect on the generation dominance proceeding 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 traditional operating companies (including the Company), Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, (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.

In October 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 and 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 in November 2006 a compliance plan in connection with the order. On April 19, 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan is not expected to have a material impact on the Company's financial statements. On November 19, 2007, Southern Company notified the FERC that the plan had been implemented and the FERC division of audits subsequently began an audit pertaining to compliance implementation and related matters, which is ongoing.

Generation Interconnection Agreements

In November 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. No other similar 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 required the modification of Tenaska's interconnection agreements, under the provisions of the order, the Company determined that no refund was payable to Tenaska. Southern Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied and Southern Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

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 expired in July and August of 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued an annual license for the Coosa developments on August 8, 2007 and issued an annual license for the Warrior developments on September 6, 2007. These annual licenses are required to be renewed each year by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses.

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 is expected to be filed with the FERC in 2011.

Upon or after the expiration of each license, the U.S. 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.

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

PSC Matters

Retail Rate Adjustments

In October 2005, the Alabama PSC approved a revision to 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% per year and any annual adjustment is limited to 5%. Retail rates remain unchanged when the return on retail common equity is projected to be between 13.0% and 14.5%. 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. On November 30, 2007, the Company made its submission of projected data for calendar year 2008. The Rate RSE increase for 2008 is 3.24%, or $147 million annually, and was effective in January 2008. Under terms of Rate RSE, the maximum increase for 2009 cannot exceed 4.76%. 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 power purchase agreements (PPAs) under Rate CNP. In April 2005, an annual adjustment to Rate CNP, associated with PPAs, decreased retail rates by approximately 0.5%, or $19 million annually. The annual PPA true-up adjustment effective in April 2006 increased retail rates by 0.5%, or $19 million annually. There was no rate adjustment associated with the annual PPA true-up adjustment in April 2007 and there will be no adjustment to the current Rate CNP to recover certificated PPA costs in April 2008. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism, based on forward-looking information, 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 operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.0% in January 2005, 1.2% in January 2006, 0.6% in January 2007, and 2.4% in January 2008. It is currently anticipated that retail rates will increase approximately 0.6% in 2009 under this provision.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the under recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per KWH effective with billings beginning July 2007 for the 30-month period ending December 2009. The previous rate of 2.400 cents per KWH had been in effect since January 2006. This increase was intended to permit recovery of energy costs based on an estimate of future energy cost, as well as the collection of the existing under recovered energy cost by the end of 2009. During the 30-month period, the Company will be allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company will pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

The Company's under recovered fuel costs as of December 31, 2007 totaled $279.8 million as compared to $301.0 million at December 31, 2006. As a result of the Alabama PSC order, the Company classified $81.7 million and $301.0 million of the under recovered regulatory clause revenues as deferred charges and other assets in the balance sheets as of December 31, 2007 and December 31, 2006, respectively. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of the recovery of the under recovered fuel costs. 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. In July 2005 and August 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.

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 four years. The second component of the NDR charge is intended to allow recovery of any 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.

At December 31, 2007, the Company had accumulated a balance of $26.1 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its prior storm cost of $51.3 million resulting from Hurricanes Dennis and Katrina. As a result, customer rates decreased by this portion of the NDR charge effective in July 2007.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expenses 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.

Income Tax Matters

Bonus Depreciation

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 (Stimulus Act) into law. The Stimulus Act includes a provision that allows 50% bonus depreciation for certain property acquired in 2008 and placed in service in 2008 or, in certain limited cases, 2009. The Company is currently assessing the financial implications of the Stimulus Act; however, the ultimate impact cannot be determined at this time.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate applicable for all years after 2009. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pre-tax pension income of approximately $17 million, $13 million, and $21 million in 2007, 2006, and 2005, respectively. Postretirement benefit costs for the Company were $27 million, $28 million, and $28 million in 2007, 2006, and 2005, 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. In addition, 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, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. 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 financial statements 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 results of operations.

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, the FERC, 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, and 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

Income Taxes

On January 1, 2007, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), which requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. The provisions of FIN 48 were applied to all tax positions beginning January 1, 2007. The adoption of FIN 48 did not have a material impact on the Company's financial statements.

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 the balance sheets. 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.

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 adopted SFAS No. 157 in its entirety on January 1, 2008, with no material effect on its financial condition or results of operations.

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 adopted SFAS No. 159 on January 1, 2008, with no material effect on its financial condition or results of operations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2007. Net cash flow from operating activities totaled $1,150 million, $956 million, and $908 million for 2007, 2006, and 2005, respectively. The $194 million increase for 2007 in net cash flow from operating activities is primarily due to an increase in price resulting in an increase to net income, an increase in deferred income tax expense, and lower cash outflows for accounts payable due to timing of payments at December 31, 2007. The $48 million increase for 2006 in operating activities primarily related to higher recovery rates for fuel and purchased power partially offset by the timing of payments for operations expenses. Fuel 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. Net cash used for investing activities totaled $1.3 billion primarily due to gross property additions to utility plant of $1.2 billion. Net cash provided from financing activities totaled $162 million, compared to $14 million in 2006. The $148 million increase is primarily due to cash inflows from proceeds of common stock and pollution control bonds, offset by redemptions of long-term debt. See FUTURE EARNINGS POTENTIAL – "Retail Fuel Cost Recovery" and "Natural Disaster Cost Recovery" for additional information.

Significant balance sheet changes for 2007 include an increase of $671 million in gross plant and an increase of $602 million in long-term debt. In 2006, significant balance sheet changes included an increase of $697 million in gross plant and an increase of $279 million in long-term debt, primarily due to an increase in environmental-related equipment.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.5% in 2007, 42.1% in 2006, and 42.2% in 2005. 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, unsecured debt, common stock, preferred stock, and preference stock. However, the type and timing of any financings 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 Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC 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 sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily 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 2008, the Company had approximately $74 million of cash and cash equivalents and $1.2 billion 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 a commercial paper program, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of $1.2 billion, of which $435 million will expire at various times during 2008. $355 million of the credit facilities expiring in 2008 allow for the execution of term loans for an additional one-year period. $800 million of credit facilities expire in 2012. 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, 2007, the Company had no commercial paper or extendible commercial notes outstanding. As of December 31, 2006, the Company had $120 million of commercial paper outstanding and no extendible commercial notes outstanding.

Financing Activities

During 2007, the Company issued $850 million of senior notes and $200 million of preference stock and incurred obligations related to the issuance of $265.5 million of tax-exempt bonds. In addition, the Company issued a total of 5.725 million shares of its common stock at $40.00 per share and realized proceeds of $229 million. The proceeds of these issuances were used to repay short-term indebtedness, and for other general corporate purposes.

Also during 2007, the Company paid at maturity $668.5 million of senior notes and redeemed $100 million of junior subordinated notes.

Subsequent to December 31, 2007, the Company issued $300 million of long-term senior notes. The proceeds were used to repay short-term indebtedness and for other general corporate purposes. Additionally, the Company redeemed 1,250 shares of its Flexible Money Market Class A Preferred Stock (Series 2003A), Stated Capital $100,000 Per Share ($125 million aggregate value).

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- or Baa3. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for coal purchases. At December 31, 2007, the maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $8 million.

The Company is also party to certain 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, 2007, the Company's exposure related to these agreements was approximately $15 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 and other derivatives that have been designated as hedges. The weighted average interest rate on $1.1 billion of long-term variable interest rate exposure that has not been hedged at January 1, 2008 was 4.19%. 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 $11 million at January 1, 2008. Subsequent to December 31, 2007, the Company entered into additional interest rate swaps hedging approximately $330 million of floating rate pollution control bonds which together with the current interest rate swaps of $246 million began decreasing the Company's variable rate exposure by $576 million. As a result, the effect of a 100 basis point change in interest rates for all currently unhedged variable rate long-term debt decreased to approximately $5.7 million. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Of the Company's remaining $497 million of variable interest rate exposure, $247 million relates to tax-exempt auction rate pollution control bonds. Recent weakness in the auction markets has resulted in higher interest rates. The Company has sent notice of conversion of all $247 million of these auction rate securities to a fixed rate interest rate determination method and plans to remarket the auction rate securities in a timely manner. None of the securities are insured or backed by letters of credit that would require approval of a guarantor or security provider. It is not expected that the higher rates as a result of the weakness in the auction markets will be material.

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 financial hedge contracts for natural 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% 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% of the Company's natural gas budget for that year.

At December 31, 2007, 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	
	2007	2006
	(in millions)	
Contracts beginning of year	**\$(32.6)**	\$ 29.0
Contracts realized or settled	**31.5**	45.0
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**0.7**	(106.6)
Contracts end of year	**\$ (0.4)**	\$ (32.6)

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

		Source of 2007 Year-End Valuation Prices	
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**\$(0.9)**	**\$(3.9)**	**\$3.0**
External sources	**0.5**	**0.5**	**-**
Models and other methods	**-**	**-**	**-**
Contracts end of year	**\$(0.4)**	**\$(3.4)**	**\$3.0**

Unrealized gains and losses from mark-to-market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's Rate ECR. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2007, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	**\$(0.7)**
Accumulated other comprehensive income	**0.5**
Net income	**(0.2)**
Total fair value	**\$(0.4)**

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 \$1.6 billion for 2008, \$1.6 billion for 2009, and \$1.0 billion for 2010. Environmental expenditures included in these estimated amounts are \$646 million, \$617 million, and \$126 million for 2008, 2009, and 2010, respectively. In addition, over the next three years, the Company estimates spending \$595 million on Plant Farley (including \$432 million for nuclear fuel), \$1,110 million on distribution facilities, and \$407 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

Actual construction costs may vary from these estimates because of changes in such factors as: business conditions; environmental statutes and 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 has 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 $760 million will be required by the end of 2010 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.

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

	2008	2009-2010	2011-2012	After 2012	Total
			(in millions)		
Long-term debt[(a)] –					
Principal	$ 410	$ 350	$ 400	$ 4,004	$ 5,164
Interest	266	487	454	4,100	5,307
Preferred stock [(b)]	125	-	-	-	125
Preferred and preference stock dividends[(c)]	46	91	91	-	228
Other derivative obligations[(d)] –					
Commodity	6	-	-	-	6
Operating leases	26	37	16	18	97
Purchase commitments[(e)] –					
Capital [(f)]	1,511	2,532	-	-	4,043
Limestone[(g)]	2	14	28	83	127
Coal	1,180	1,678	1,159	1,642	5,659
Nuclear fuel	60	92	93	42	287
Natural gas [(h)]	524	497	33	126	1,180
Purchased power	89	126	2	-	217
Long-term service agreements[(i)]	17	36	33	50	136
Postretirement benefits trust[(j)]	23	38	-	-	61
Total	$4,285	$5,978	$2,309	$10,065	$22,637

(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, 2008, 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) On October 26, 2007, the Company announced the redemption on January 1, 2008 of 1,250 shares of Flexible Money Market Class A Preferred Stock (Series 2003A), Cumulative, Par Value $1 Per Share (Stated Capital $100,000 Per Share).

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

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

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2007, 2006, and 2005 were $1.19 billion, $1.10 billion, and $1.04 billion, respectively.

(f) 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, 2007, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company is constructing certain equipment and has entered into various long-term commitments for the procurement of limestone to be used in such equipment.

(h) 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, 2007.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) 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 2007 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, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, completion of construction projects, filings with state and federal regulatory authorities, 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, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in 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, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuel;
- effects of inflation;
- 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, droughts, 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, 2007, 2006, and 2005

Alabama Power Company 2007 Annual Report

	2007	2006	2005
		(in thousands)	
Operating Revenues:			
Retail revenues	**$4,406,956**	$3,995,731	$3,621,421
Wholesale revenues --			
Non-affiliates	**627,047**	634,552	551,408
Affiliates	**144,089**	216,028	288,956
Other revenues	**181,901**	168,417	186,039
Total operating revenues	**5,359,993**	5,014,728	4,647,824
Operating Expenses:			
Fuel	**1,762,418**	1,672,831	1,457,301
Purchased power --			
Non-affiliates	**96,928**	124,022	188,733
Affiliates	**341,461**	302,045	268,751
Other operations	**764,155**	720,296	682,308
Maintenance	**422,080**	376,682	361,832
Depreciation and amortization	**471,536**	451,018	426,506
Taxes other than income taxes	**286,579**	258,135	248,854
Total operating expenses	**4,145,157**	3,905,029	3,634,285
Operating Income	**1,214,836**	1,109,699	1,013,539
Other Income and (Expense):			
Allowance for equity funds used during construction	**35,425**	18,253	20,281
Interest income	**19,545**	20,897	17,144
Interest expense, net of amounts capitalized	**(273,737)**	(252,282)	(213,604)
Other income (expense), net	**(29,144)**	(23,758)	(20,461)
Total other income and (expense)	**(247,911)**	(236,890)	(196,640)
Earnings Before Income Taxes	**966,925**	872,809	816,899
Income taxes	**351,198**	330,345	284,715
Net Income	**615,727**	542,464	532,184
Dividends on Preferred and Preference Stock	**36,145**	24,734	24,289
Net Income After Dividends on Preferred and Preference Stock	**$ 579,582**	$ 517,730	$ 507,895

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2007, 2006, and 2005

Alabama Power Company 2007 Annual Report

	2007	2006	2005
		(in thousands)	
Operating Activities:			
Net income	**$615,727**	$ 542,464	$ 532,184
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**548,959**	524,313	498,914
Deferred income taxes and investment tax credits, net	**21,269**	(27,562)	106,765
Deferred revenues	**-**	(1,274)	(12,502)
Allowance for equity funds used during construction	**(35,425)**	(18,253)	(20,281)
Pension, postretirement, and other employee benefits	**(18,781)**	(15,196)	(22,117)
Stock option expense	**4,900**	4,848	-
Tax benefit of stock options	**1,118**	610	17,400
Hedge settlements	**(5,530)**	18,006	(21,445)
Storm damage accounting order	**-**	-	48,000
Other, net	**(8,120)**	12,832	(15,491)
Changes in certain current assets and liabilities --			
Receivables	**(5,797)**	(33,260)	(255,481)
Fossil fuel stock	**(33,840)**	(28,179)	(44,632)
Materials and supplies	**(32,543)**	(25,711)	(16,935)
Other current assets	**22,354**	38,645	1,199
Accounts payable	**78,508**	(49,725)	80,951
Accrued taxes	**(17,248)**	1,124	(5,381)
Accrued compensation	**4,194**	(6,157)	3,273
Other current liabilities	**10,098**	18,486	33,675
Net cash provided from operating activities	**1,149,843**	956,011	908,096
Investing Activities:			
Property additions	**(1,157,186)**	(933,306)	(860,807)
Investment in restricted cash from pollution control bonds	**(97,775)**	-	-
Distribution of restricted cash from pollution control bonds	**78,043**	-	-
Nuclear decommissioning trust fund purchases	**(334,275)**	(286,551)	(224,716)
Nuclear decommissioning trust fund sales	**333,409**	285,685	223,850
Cost of removal net of salvage	**(48,932)**	(40,834)	(61,314)
Other	**(26,621)**	(1,777)	(9,738)
Net cash used for investing activities	**(1,253,337)**	(976,783)	(932,725)
Financing Activities:			
Increase (decrease) in notes payable, net	**(119,670)**	(195,609)	315,278
Proceeds --			
Senior notes	**850,000**	950,000	250,000
Preferred and preference stock	**200,000**	150,000	-
Common stock issued to parent	**229,000**	120,000	40,000
Capital contributions	**27,867**	27,160	22,473
Gross excess tax benefit of stock options	**2,556**	1,291	-
Pollution control bonds	**265,500**	-	21,450
Redemptions --			
Senior notes	**(668,500)**	(546,500)	(225,000)
Pollution control bonds	**-**	(2,950)	(21,450)
Capital leases	**-**	-	(5)
Other long-term debt	**(103,093)**	-	-
Payment of preferred and preference stock dividends	**(31,380)**	(24,318)	(22,759)
Payment of common stock dividends	**(465,000)**	(440,600)	(409,900)
Other	**(25,709)**	(24,635)	(2,697)
Net cash provided from (used for) financing activities	**161,571**	13,839	(32,610)
Net Change in Cash and Cash Equivalents	**58,077**	(6,933)	(57,239)
Cash and Cash Equivalents at Beginning of Year	**15,539**	22,472	79,711
Cash and Cash Equivalents at End of Year	**$ 73,616**	$ 15,539	$ 22,472
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $17,961, $7,930, and $8,161 capitalized, respectively)	**$248,289**	$245,387	$179,658
Income taxes (net of refunds)	**340,951**	345,803	159,600

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

BALANCE SHEETS

At December 31, 2007 and 2006

Alabama Power Company 2007 Annual Report

Assets	2007	2006
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 73,616**	$ 15,539
Restricted cash	**19,732**	-
Receivables --		
Customer accounts receivable	**357,355**	323,202
Unbilled revenues	**95,278**	90,596
Under recovered regulatory clause revenues	**232,226**	32,451
Other accounts and notes receivable	**42,745**	49,708
Affiliated companies	**61,250**	70,836
Accumulated provision for uncollectible accounts	**(7,988)**	(7,091)
Fossil fuel stock, at average cost	**182,963**	153,120
Materials and supplies, at average cost	**287,994**	255,664
Vacation pay	**50,266**	46,465
Prepaid expenses	**72,952**	76,265
Other	**19,610**	66,663
Total current assets	**1,487,999**	1,173,418
Property, Plant, and Equipment:		
In service	**16,669,142**	15,997,793
Less accumulated provision for depreciation	**5,950,373**	5,636,475
	10,718,769	10,361,318
Nuclear fuel, at amortized cost	**137,146**	137,300
Construction work in progress	**928,182**	562,119
Total property, plant, and equipment	**11,784,097**	11,060,737
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**48,664**	47,486
Nuclear decommissioning trusts, at fair value	**542,846**	513,521
Other	**31,146**	35,980
Total other property and investments	**622,656**	596,987
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**347,193**	354,225
Prepaid pension costs	**989,085**	722,287
Deferred under recovered regulatory clause revenues	**81,650**	301,048
Other regulatory assets	**224,792**	279,661
Other	**209,153**	166,927
Total deferred charges and other assets	**1,851,873**	1,824,148
Total Assets	**$15,746,625**	$14,655,290

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

BALANCE SHEETS
At December 31, 2007 and 2006
Alabama Power Company 2007 Annual Report

Liabilities and Stockholder's Equity	2007	2006
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 535,152**	$ 668,646
Notes payable	-	119,670
Accounts payable --		
Affiliated	**193,518**	162,951
Other	**308,177**	263,506
Customer deposits	**67,722**	62,978
Accrued taxes --		
Income taxes	**45,958**	3,120
Other	**29,198**	29,696
Accrued interest	**55,263**	53,573
Accrued vacation pay	**42,138**	38,767
Accrued compensation	**92,385**	87,194
Other	**55,331**	79,907
Total current liabilities	**1,424,842**	1,570,008
Long-term Debt (See accompanying statements)	**4,750,196**	4,148,185
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,065,264**	2,116,575
Deferred credits related to income taxes	**93,709**	98,941
Accumulated deferred investment tax credits	**180,578**	188,582
Employee benefit obligations	**349,974**	375,940
Asset retirement obligations	**505,794**	476,460
Other cost of removal obligations	**613,616**	600,278
Other regulatory liabilities	**637,040**	399,822
Other	**31,417**	35,805
Total deferred credits and other liabilities	**4,477,392**	4,292,403
Total Liabilities	**10,652,430**	10,010,596
Preferred and Preference Stock (See accompanying statements)	**683,512**	612,407
Common Stockholder's Equity (See accompanying statements)	**4,410,683**	4,032,287
Total Liabilities and Stockholder's Equity	**$15,746,625**	$14,655,290
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2007 and 2006
Alabama Power Company 2007 Annual Report

	2007	2006	2007	2006
		(in thousands)		*(percent of total)*
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
4.75% to 5.5% due 2042	**$ 206,186**	$ 309,279		
Long-term notes payable --				
3.50% to 7.125% due 2007	**-**	500,000		
Floating rate (5.624% at 1/1/07) due 2007	**-**	168,500		
3.125% to 5.375% due 2008	**410,000**	410,000		
Floating rate (5.22% at 1/1/08) due 2009	**250,000**	250,000		
4.70% due 2010	**100,000**	100,000		
5.10% due 2011	**200,000**	200,000		
4.85% due 2012	**200,000**	-		
5.125% to 6.375% due 2016-2047	**2,975,000**	2,325,000		
Total long-term notes payable	**4,135,000**	$3,953,500		
Other long-term debt --				
Pollution control revenue bonds --				
Variable rates (2.67% to 5.20% at 1/1/08)				
due 2015-2036	**822,690**	557,190		
Total other long-term debt	**822,690**	557,190		
Capitalized lease obligations	**231**	377		
Unamortized debt premium (discount), net	**(3,759)**	(3,515)		
Total long-term debt (annual interest				
requirement -- $266.3 million)	**5,160,348**	4,816,831		
Less amount due within one year	**410,152**	668,646		
Long-term debt excluding amount due within one year	**4,750,196**	4,148,185	**48.3%**	47.1%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2007 and 2006
Alabama Power Company 2007 Annual Report

	2007	2006	2007	2006
	(in thousands)		*(percent of total)*	
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 capital	**123,331**	123,331		
Preference stock				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63% to 6.50%				
- 14,000,000 shares				
(non-cumulative) $25 stated value	**343,466**	147,361		
Total preferred and preference stock				
(annual dividend requirement -- $45.7 million)	**808,512**	612,407		
Less amount due within one year	**125,000**	-		
Preferred and preference stock				
excluding amount due within one year	**683,512**	612,407	**6.9**	7.0
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 2007: 25,000,000 shares				
- 2006: 25,000,000 shares				
Outstanding - 2007: 17,975,000 shares	**719,000**	490,000		
- 2006: 12,250,000 shares				
Paid-in capital	**2,065,298**	2,028,963		
Retained earnings	**1,630,832**	1,516,245		
Accumulated other comprehensive income (loss)	**(4,447)**	(2,921)		
Total common stockholder's equity	**4,410,683**	4,032,287	**44.8**	45.9
Total Capitalization	**$9,844,391**	$8,792,879	**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, 2007, 2006, and 2005

Alabama Power Company 2007 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (Loss)	Total
			(in thousands)		
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 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**
Net income after dividends on preferred and preference stock	-	-	**579,582**	-	**579,582**
Issuance of common stock	**229,000**	-	-	-	**229,000**
Capital contributions from parent company	-	**36,441**	-	-	**36,441**
Other comprehensive income (loss)	-	-	-	**(1,526)**	**(1,526)**
Cash dividends on common stock	-	-	**(465,000)**	-	**(465,000)**
Other	-	**(106)**	**5**	-	**(101)**
Balance at December 31, 2007	**$719,000**	**$2,065,298**	**$1,630,832**	**$(4,447)**	**$4,410,683**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2007, 2006, and 2005

Alabama Power Company 2007 Annual Report

	2007	2006	2005
		(in thousands)	
Net income after dividends on preferred and preference stock	**$579,582**	$517,730	$507,895
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1,226), $155, and $5,523, respectively	**(2,017)**	255	9,085
Reclassification adjustment for amounts included in net income, net of tax of $298, $(3,696), and $(1,333), respectively	**491**	(6,080)	(2,193)
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $1,109, and $(1,422), respectively	-	1,768	(2,338)
Total other comprehensive income (loss)	**(1,526)**	(4,057)	4,554
Comprehensive Income	**$578,056**	$513,673	$512,449

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, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power, Gulf Power, and Mississippi Power – 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 and 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. The investments in synthetic fuels ended on December 31, 2007. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

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.

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.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation. These reclassifications had no effect on total assets, net income, or cash flows.

The balance sheets and the statements of cash flows have been modified to combine "Long-term Debt Payable to Affiliate Trusts" into "Long-term Debt." Correspondingly, the statements of income were modified to report "Interest expense to affiliate trusts" together with "Interest expense, net of amounts capitalized."

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 $299 million, $266 million, and $246 million during 2007, 2006, and 2005, 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 $182 million, $162 million, and $157 million during 2007, 2006, and 2005, 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 $9.8 million in 2007, $8.6 million in 2006, and $8.2 million in 2005. See Note 4 for additional information.

Southern Company held a 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel, until July 2006, when the ownership interest was terminated. Subsequent to the termination of the membership interest in AFP, the Company continued to purchase fuel from AFP in the amount of $462.1 and $244.4 million in 2007 and 2006, respectively. 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 year ended 2005 were $202.2 million and $265.7 million, respectively. In addition, the Company had an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $58.1 million, $56.5 million, and $31.5 million in 2007, 2006, and 2005, respectively. The synthetic fuel purchases and related party transactions were terminated as of December 31, 2007.

The Company had an agreement with Southern Power under which the Company operated and maintained Plant Harris at cost. On August 1, 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power labor and other specifically requested services. In 2007, 2006, and 2005, the Company billed Southern Power $2.4 million, $2.2 million, and $1.9 million, respectively, under these agreements. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2007, 2006, and 2005 totaled $66.3 million, $61.7 million, and $63.6 million, respectively. The Company also provides the fuel, at cost, associated with the PPA and the fuel cost recognized by the Company was $108.1 million in 2007, $77.8 million in 2006, and $81.3 million in 2005. 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, 2007 and 2006. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

In 2007, the Company purchased plots of land in Prattville, Alabama and Chilton County, Alabama from Southern Power. The total purchase price was $4.3 million and is recorded in "Property additions" on the statements of cash flows.

The Company had an agreement with SouthernLINC Wireless to provide digital wireless communications services to the Company. Costs for these services amounted to $5.1 million, $4.9 million, and $5.7 million during 2007, 2006, and 2005, 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 Mississippi Power in 2005, assistance provided to aid in storm restoration, including Company labor, contract labor, and materials, caused an increase in these activities. The total amount of storm restoration provided to Mississippi Power in 2005 was $8.0 million. In 2005, the Company received assistance from affiliated companies in the amount of $5.0 million. 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. Wholesale 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% 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:

	2007	2006	Note
	(in millions)		
Deferred income tax charges	**$ 347**	$ 354	(a)
Loss on reacquired debt	**87**	94	(b)
Vacation pay	**50**	46	(c)
Under recovered regulatory clause revenues	**314**	334	(d)
Fuel-hedging assets	**6**	36	(e)
Other assets	**6**	6	(d)
Asset retirement obligations	**(150)**	(152)	(a)
Other cost of removal obligations	**(614)**	(600)	(a)
Deferred income tax credits	**(94)**	(99)	(a)
Natural disaster reserve (prior storms)	**-**	17	(d)
Fuel-hedging liabilities	**(5)**	(3)	(e)
Mine reclamation and remediation	**(14)**	(16)	(d)
Nuclear outage	**2**	(12)	(d)
Deferred purchased power	**(20)**	(19)	(d)
Natural disaster reserve (future storms)	**(26)**	(13)	(d)
Other liabilities	**(3)**	(3)	(d)
Overfunded retiree benefit plans	**(423)**	(183)	(f)
Underfunded retiree benefit plans	**138**	183	(f)
Total	**$(399)**	$ (30)	

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

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

(e) 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.

(f) Recovered and amortized over the average remaining service period which may range up to 14 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 United States, acting through 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.

On July 9, 2007, the U.S. Court of Federal Claims awarded the Company $17.3 million, representing all of the direct costs of the expansion of spent nuclear fuel storage facilities from 1998 through 2004. On July 24, 2007, the government filed a motion for reconsideration, which was denied on November 1, 2007. The government filed an appeal on January 2, 2008. No amounts have been recognized in the financial statements as of December 31, 2007. The final outcome of this matter cannot be determined at this time, but no material impact on net income is expected as any award received is expected to be returned to customers.

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 and was fully amortized in September 2007. 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.

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.

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information on the effect of adopting FIN 48.

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:

	2007	2006
	(in millions)	
Generation	**$ 8,541**	$ 8,312
Transmission	**2,435**	2,308
Distribution	**4,586**	4,352
General	**1,095**	1,017
Plant acquisition adjustment	**12**	9
Total plant in service	**$16,669**	$15,998

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 2007, the Company accrued $40.3 million and paid $27.6 million for an outage at Plant Farley Unit 1 and $27.1 million for an outage at Plant Farley Unit 2. At December 31, 2007, the reserve balance totaled $(2.0) 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% in 2007 and 2006 and 2.9% in 2005. 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

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are 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. 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.

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, 2007 was $543 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. In connection with the adoption of FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (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 Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" 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:

	2007	2006
	(in millions)	
Balance beginning of year	**$476**	$446
Liabilities incurred	**-**	3
Liabilities settled	**(3)**	(3)
Accretion	**33**	30
Cash flow revisions	**-**	-
Balance end of year	**$506**	$476

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has 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, 2007 were as follows:

2007	**Unrealized Gains**	**Other-than-Temporary Impairments**	**Fair Value**
		(in millions)	
Equity	**\$130.8**	**\$(15.7)**	**\$385.4**
Debt	**7.0**	**(3.5)**	**140.2**
Other	**0.1**	**-**	**17.2**
Total	**\$137.9**	**\$(19.2)**	**\$542.8**

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

The contractual maturities of debt securities at December 31, 2007 are as follows: \$33.1 million in 2008; \$28.8 million in 2009-2012; \$17.0 million in 2013-2017; and \$65.8 million thereafter.

Sales of the securities held in the trust funds resulted in cash proceeds of \$333.4 million, \$285.7 million, and \$223.8 million in 2007, 2006, and 2005, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were \$34.6 million and \$37.2 million, respectively, in 2007 and \$22.0 million and \$18.2 million, respectively, in 2006. Net realized gains were \$9.9 million in 2005. Realized gains and other-than-temporary impairment losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and other-than-temporary impairment losses are considered non-cash transactions for purposes of the statements of cash flows.

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, 2007, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds, at fair value	\$543
Internal reserves	27
Total	\$570

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% and a trust earnings rate of 7.0%. 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. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.4% in 2007, 8.8% in 2006, and 8.8% in 2005. AFUDC, net of income tax, as a percent of net income after dividends on preferred and preference stock was 8.0% in 2007, 4.5% in 2006, and 5.0% in 2005.

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 four years assuming the Company experiences no additional storms. The second component of the NDR charge is intended to allow recovery of any existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. 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. 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, 2007, the Company had accumulated a balance of $26.1 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its prior storm cost of $51.3 million resulting from Hurricanes Dennis and Katrina. As a result, customer rates decreased by this portion of the NDR charge effective July 1, 2007.

As revenue from the NDR charge is recognized, an equal amount of operations 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.

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 years ended December 31, 2007 and 2006 was recognized as the requisite service was rendered and included: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as of January 1, 2006, for which the requisite service had not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation", 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 $4.9 million and $3.0 million, respectively, for the year ended December 31, 2007 and $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 the increase in financing cash flows for the years ended December 31, 2007 and December 31, 2006 was $2.6 million and $1.3 million, respectively.

For the year ended December 31, 2005, prior to the adoption of SFAS No. 123(R), the pro forma impact on net income of fair-value accounting for options granted was as follows:

2005	As Reported	Options Impact After Tax	Pro Forma
		(in millions)	
Net Income	$508	$(3)	$505

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

The estimated fair values of stock options granted in 2007, 2006, and 2005 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used 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 was 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:

Year Ended December 31	2007	2006	2005
Expected volatility	**14.8%**	16.9%	17.9%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**4.6%**	4.6%	3.9%
Dividend yield	**4.3%**	4.4%	4.4%
Weighted average grant-date fair value	**$4.12**	$4.15	$3.90

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 amounts did not equal fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2007	**$5,160**	**$5,079**
2006	4,816	4,768

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 prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158) the 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 "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 included in Long-term Debt 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 $2.3 million and $2.6 million at December 31, 2007 and 2006, 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, 2008. 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 and the FERC. For the year ending December 31, 2008, postretirement trust contributions are expected to total approximately $22.9 million.

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

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.3 billion in 2007 and 2006. Changes during the year in the projected benefit obligations and fair value of plan assets were as follows:

	2007	2006
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,394**	$1,421
Service cost	**35**	37
Interest cost	**82**	76
Benefits paid	**(70)**	(69)
Plan amendments	**10**	2
Actuarial (gain) loss	**(31)**	(73)
Balance at end of year	**1,420**	1,394
Change in plan assets		
Fair value of plan assets at beginning of year	**2,038**	1,875
Actual return on plan assets	**346**	228
Employer contributions	**4**	4
Benefits paid	**(70)**	(69)
Fair value of plan assets at end of year	**2,318**	2,038
Funded status at end of year	**898**	644
Fourth quarter contributions	**2**	1
Prepaid pension asset, net	**$ 900**	$ 645

At December 31, 2007, the projected benefit obligations for the qualified and non-qualified pension plans were $1.3 billion and $91 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	**2007**	2006
Domestic equity	36%	**38%**	38%
International equity	24	**24**	23
Fixed income	15	**15**	16
Real estate	15	**16**	16
Private equity	10	**7**	7
Total	100%	**100%**	100%

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

	2007	2006
	(in millions)	
Prepaid pension asset	**$ 989**	$ 722
Other regulatory assets	**43**	36
Current liabilities, other	**(5)**	(5)
Other regulatory liabilities	**(423)**	(183)
Employee benefit obligations	**(84)**	(72)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2007 and December 31, 2006 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2008:

	Prior Service Cost	**Net(Gain)/Loss**
	(in millions)	
Balance at December 31, 2007:		
Regulatory assets	**$14**	**$ 29**
Regulatory liabilities	**56**	**(479)**
Total	**$70**	**$(450)**
Balance at December 31, 2006:		
Regulatory assets	$ 6	$ 30
Regulatory liabilities	64	(247)
Total	$70	$(217)
Estimated amortization in net periodic pension cost in 2008:		
Regulatory assets	$ 2	$ 2
Regulatory liabilities	8	-
Total	$10	$ 2

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the year ended December 31, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in millions)	
Beginning balance	$36	$(183)
Net (gain)/loss	1	(232)
Change in prior service costs	10	-
Reclassification adjustments:		
Amortization of prior service costs	(2)	(8)
Amortization of net gain	(2)	-
Total reclassification adjustments	(4)	(8)
Total change	7	(240)
Ending balance	$43	$(423)

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

	2007	2006	2005
		(in millions)	
Service cost	**$ 35**	$ 37	$ 33
Interest cost	**82**	77	74
Expected return on plan assets	**(146)**	(139)	(139)
Recognized net (gain) loss	**2**	3	2
Net amortization	**10**	9	9
Net periodic pension (income)	**$ (17)**	$ (13)	$ (21)

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, 2007, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2008	$ 74
2009	76
2010	79
2011	89
2012	93
2013 to 2017	561

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:

	2007	2006
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 490**	$ 490
Service cost	**7**	7
Interest cost	**28**	26
Benefits paid	**(23)**	(22)
Actuarial (gain) loss	**(24)**	(13)
Retiree drug subsidy	**2**	2
Balance at end of year	**480**	490
Change in plan assets		
Fair value of plan assets at beginning of year	**259**	245
Actual return on plan assets	**36**	23
Employer contributions	**23**	27
Benefits paid	**(21)**	(36)
Fair value of plan assets at end of year	**297**	259
Funded status at end of year	**(183)**	(231)
Fourth quarter contributions	**28**	26
Accrued liability	**$(155)**	$(205)

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	2007	2006
Domestic equity	47%	**46%**	46%
International equity	13	**15**	16
Fixed income	29	**29**	28
Real estate	7	**7**	7
Private equity	4	**3**	3
Total	100%	**100%**	100%

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

	2007	2006
	(in millions)	
Regulatory assets	**$ 95**	$ 147
Employee benefit obligations	**(155)**	(205)

Presented below are the amounts included in regulatory assets at December 31, 2007 and December 31, 2006 related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2008.

	Prior Service Cost	Net (Gain)/Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2007:			
Regulatory asset	**$55**	**$20**	**$20**
Balance at December 31, 2006:			
Regulatory asset	$59	$63	$25
Estimated amortization as net periodic postretirement cost in 2008:			
Regulatory asset	$ 5	$ -	$ 4

The change in the balance of regulatory assets related to the other postretirement benefit plans for the year ended December 31, 2007 is presented in the following table:

	Regulatory Assets
	(in millions)
Beginning balance	$147
Net gain	(41)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(4)
Amortization of prior service costs	(5)
Amortization of net gain	(2)
Total reclassification adjustments	(11)
Total change	(52)
Ending balance	$ 95

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

	2007	2006	2005
		(in millions)	
Service cost	**$ 7**	$ 7	$ 7
Interest cost	**28**	26	26
Expected return on plan assets	**(19)**	(17)	(16)
Net amortization	**11**	12	11
Net postretirement cost	**$ 27**	$ 28	$ 28

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2007, 2006, and 2005 by approximately $10.7 million, $11.1 million, and $8.7 million, respectively.

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)	
2008	$ 27	$ (3)	$ 24
2009	29	(3)	26
2010	32	(3)	29
2011	35	(4)	31
2012	37	(4)	33
2013 to 2017	206	(28)	178

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 were calculated in 2004, for the 2005 plan year, using a discount rate of 5.75%.

	2007	2006	2005
Discount	**6.30%**	6.00%	5.50%
Annual salary increase	**3.75**	3.50	3.00
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.75% for 2008, decreasing gradually to 5.25% 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% would affect the APBO and the service and interest cost components at December 31, 2007 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$33	$28
Service and interest costs	2	2

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2007, 2006, and 2005 were $17 million, $14 million, and $14 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, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including 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.

In June 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. In August 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 all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, and the appeal was stayed by the Appeals Court pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007. On October 5, 2007, the U.S. District Court for the Northern District of Alabama issued an order in the Company's case indicating a willingness to re-evaluate its previous decision in light of the Supreme Court's Duke Energy opinion. On December 21, 2007, the Eleventh Circuit vacated the district court's decision in the Company's case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. The final outcome of these matters cannot be determined at this time.

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 or affect the timing of currently budgeted 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.

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 and no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has received authority from the Alabama PSC to recover approved environmental compliance costs through a specific retail rate clause that is adjusted annually. See "Retail Regulatory Matters – Rate CNP" herein for additional information.

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 the 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 that ended in May 2006 could be subject to refund to a cost-based rate level.

In late June and July 2007, hearings were held in this proceeding and the presiding administrative law judge issued an initial decision on November 9, 2007 regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company 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 and could also result in refunds of up to $3.9 million, plus interest. The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter.

On June 21, 2007, the FERC issued its final rule regarding market-based rate authority. The FERC generally retained its current market-based rate standards. The impact of this order and its effect on the generation dominance proceeding cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (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 traditional operating companies (including the Company), Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (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.

In October 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 and 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 in November 2006 a compliance plan in connection with the order. On April 19, 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan is not expected to have a material impact on the Company's financial statements. On November 19, 2007, Southern Company notified the FERC that the plan had been implemented and the FERC division of audits subsequently began an audit pertaining to compliance implementation and related matters, which is ongoing.

Generation Interconnection Agreements

In November 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. No other similar 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 required the modification of Tenaska's interconnection agreements, under the provisions of the order, the Company determined that no refund was payable to Tenaska. Southern Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied and Southern Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. 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. Retail rates remain unchanged when the retail return on common equity ranges between 13.0% and 14.5%. In October 2005, the Alabama PSC approved a revision to Rate RSE. Prior to January 2007, annual adjustments were limited to 3.0%. 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% per year and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the return on retail common equity is projected to be between 13.0% and 14.5%. 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. On November 30, 2007, the Company made its submission of projected data for calendar year 2008. The Rate RSE increase for 2008 is 3.24%, or $147 million annually, and was effective in January 2008. Under the terms of Rate RSE, the maximum increase for 2009 cannot exceed 4.76%. See "Rate CNP" for additional information.

Rate CNP

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 CNP. In April 2005, an annual adjustment to Rate CNP decreased retail rates by approximately 0.5%, or $19 million annually. The annual true-up adjustment effective in April 2006 increased retail rates by 0.5%, or $19 million annually. There was no rate adjustment associated with the annual true-up adjustment in April 2007 and there will be no adjustment to the current Rate CNP to recover certificated PPA costs in April 2008.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism, based on forward looking information, 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 operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.0% in January 2005, 1.2% in January 2006, 0.6% in January 2007, and 2.4% in January 2008.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under an energy cost recovery clause (Rate ECR) approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the under recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per kilowatt-hour (KWH) effective with billings beginning July 2007 for the 30-month period ending December 2009. The previous rate of 2.400 cents per KWH had been in effect since January 2006. This increase was intended to permit recovery of energy costs based on an estimate of future energy cost, as well as the collection of the existing under recovered energy cost by the end of 2009. During the 30-month period, the Company will be allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company will pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

The Company's under recovered fuel costs as of December 31, 2007 totaled $279.8 million as compared to $301.0 million at December 31, 2006. As a result of the Alabama PSC order, the Company classified $81.7 million and $301.0 million of the under recovered regulatory clause revenues as deferred charges and other assets in the balance sheets as of December 31, 2007 and December 31, 2006, respectively. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of the recovery of the under recovered fuel costs.

Natural Disaster Cost Recovery

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.

In July 2005 and August 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 operations 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 operations 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 four 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.

At December 31, 2007, the Company had accumulated a balance of $26.1 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its prior storm cost of $51.3 million resulting from Hurricanes Dennis and Katrina. As a result, customer rates decreased by this portion of the NDR charge effective in July 2007.

As revenue from the NDR charge is recognized, an equal amount of operations 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 $105 million in 2007, $95 million in 2006, and $90 million in 2005 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, 2007, the capitalization of SEGCO consisted of $66 million of equity and $104 million of debt on which the annual interest requirement is $3.2 million. SEGCO paid dividends totaling $2.6 million in 2007, $8.5 million in 2006, and $7.7 million in 2005, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% 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, 2007 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Company Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00% (1)	$121	$ 69
Plant Miller Units 1 and 2	1,320	91.84% (2)	965	418

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with Alabama Electric Cooperative, Inc.

At December 31, 2007, the Company's Plant Miller portion of construction work in progress was $49.1 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, State of Mississippi, 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 it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

In 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, 2007 and 2006, the Company had $32.0 million and $34.9 million in accumulated deferred income taxes and $2.9 million and $3.1 million in accrued taxes – income taxes, respectively, payable to these subsidiaries, on the balance sheets.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2007	2006	2005
		(in millions)	
Federal –			
Current	**$287**	$302	$151
Deferred	**17**	(25)	81
	304	277	232
State –			
Current	**43**	56	27
Deferred	**4**	(3)	26
	47	53	53
Total	**$351**	$330	$285

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:

	2007	2006
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,766**	$1,687
Property basis differences	**341**	341
Premium on reacquired debt	**36**	39
Pension and other benefits	**340**	230
Fuel clause under recovered	**128**	137
Regulatory assets associated with employee benefit obligations	**90**	111
Asset retirement obligations	**27**	28
Regulatory assets associated with asset retirement obligations	**187**	172
Storm reserve	**-**	10
Other	**60**	57
Total	**2,975**	2,812
Deferred tax assets:		
Federal effect of state deferred taxes	**121**	118
State effect of federal deferred taxes	**96**	62
Unbilled revenue	**31**	25
Storm reserve	**3**	-
Pension and other benefits	**126**	142
Other comprehensive losses	**10**	10
Regulatory liabilities associated with employee benefit obligations	**178**	77
Asset retirement obligations	**214**	200
Other	**88**	83
Total	**867**	717
Total deferred tax liabilities, net	**2,108**	2,095
Portion included in current (liabilities) assets, net	**(43)**	22
Accumulated deferred income taxes in the balance sheets	**$2,065**	$2,117

At December 31, 2007, the Company's tax-related regulatory assets and liabilities were $347 million and $94 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.

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 2007, $8.0 million in 2006, and $8.8 million in 2005. At December 31, 2007, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2007	2006	2005
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.2**	4.0	4.2
Non-deductible book depreciation	**0.9**	1.0	1.1
Differences in prior years' deferred and current tax rates	**(0.2)**	(0.3)	(4.1)
AFUDC-equity	**(1.3)**	(0.7)	(0.9)
Production activities deduction	**(0.6)**	(0.2)	(0.1)
Other	**(0.7)**	(0.9)	(0.3)
Effective income tax rate	**36.3%**	37.9%	34.9%

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% 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.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to United States production activities as defined in Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate applicable for all years after 2009. The increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $7.8 million over the 2006 deduction. The resulting additional tax benefit was over $3 million.

Unrecognized Tax Benefits

On January 1, 2007, the Company adopted FIN 48 which requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties.

Prior to the adoption of FIN 48, the Company had unrecognized tax benefits, which were previously accrued under SFAS No. 5, "Accounting for Contingencies," of approximately $1.2 million. The total $1.2 million in unrecognized tax benefits would impact the Company's effective tax rate if recognized. For 2007, the total amount of unrecognized tax benefits increased by $3.6 million, resulting in a balance of $4.8 million as of December 31, 2007.

Changes during the year in unrecognized tax benefits were as follows:

	2007
	(in millions)
Unrecognized tax benefits as of adoption	$1.2
Tax positions from current periods	1.5
Tax positions from prior periods	2.1
Reductions due to settlements	-
Reductions due to expired statute of limitations	-
Balance at end of year	$4.8

Impact on the Company's effective tax rate, if recognized, is as follows:

	2007
	(in millions)
Tax positions impacting the effective tax rate	$4.8
Tax positions not impacting the effective tax rate	-
Balance at end of year	$4.8

Accrued interest for unrecognized tax benefits:

	2007
	(in millions)
Interest accrued as of adoption	$ -
Interest accrued during the year	0.4
Balance at end of year	$0.4

The Company classifies interest on tax uncertainties as interest expense. Net interest accrued for the year ended December 31, 2007 was $0.4 million. The Company did not accrue any penalties on uncertain tax positions.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

It is reasonably possible that the amount of the unrecognized benefit with respect to certain of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible settlement of the production activities deduction methodology and/or the conclusion or settlement of federal or state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

6. FINANCING

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 $206 million, which constitute substantially all assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable. 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, 2007, preferred securities of $200 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 loans to the Company from public authorities of funds or 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. The Company incurred obligations related to the issuance of $265.5 million of tax-exempt bonds in 2007. Proceeds from certain issuances are restricted until expenditures are incurred.

Senior Notes

The Company issued a total of $850 million of unsecured senior notes in 2007. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes.

At December 31, 2007 and 2006, the Company had $4.1 billion and $4.0 billion, respectively, of senior notes outstanding. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2007.

Subsequent to December 31, 2007, the Company issued $300 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 2007, the Company issued eight million new shares of preference stock at $25.00 stated capital per share and realized proceeds of $200 million. In addition, the Company issued 5.725 million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $229 million. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes.

Subsequent to December 31, 2007, the Company redeemed 1,250 shares of its Flexible Money Market Class A Preferred Stock (Series 2003A), Stated Capital $100,000 Per Share ($125 million aggregate value).

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and 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 (typically 5 or 10 years after the date of issuance).

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Securities Due Within One Year

At December 31, 2007, the Company had scheduled maturities and redemptions of senior notes and preferred stock due within one year totaling $535 million. At December 31, 2006, the Company had scheduled maturities and redemptions of senior notes due within one year totaling $669 million.

Debt maturities through 2012 applicable to total long-term debt are as follows: $410 million in 2008; $250 million in 2009; $100 million in 2010; $200 million in 2011; and $200 million in 2012.

Assets Subject to Lien

In 2006, the Company discharged its remaining outstanding first mortgage bond obligations and the direct first lien on substantially all of the Company's fixed property and franchises was removed. 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, as of December 31, 2007.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $1.2 billion (including $582 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds), of which $435 million will expire at various times during 2008. $355 million of the credit facilities expiring in 2008 allow for the execution of one-year term loans. $800 million of credit facilities expire in 2012.

Most 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 one-fourth of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% 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, 2007, 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, 2007, the Company had no commercial paper or extendible commercial notes outstanding. As of December 31, 2006, the Company had $120 million of commercial paper outstanding, and no extendible commercial notes outstanding. During 2007 and 2006, the peak amount outstanding for short-term borrowings was $214 million and $411 million, respectively. The average amount outstanding in 2007 and 2006 was $36 million and $45 million, respectively. The average annual interest rate on short-term borrowings in 2007 was 5.34% and in 2006 was 4.76%. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2007, the Company had regulatory approval to have outstanding up to $2.0 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 2007, 2006, and 2005.

At December 31, 2007, the fair value gains/(losses) of derivative energy contracts were reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	**$(0.7)**
Accumulated other comprehensive income	**0.5**
Net income	**(0.2)**
Total fair value	**$(0.4)**

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 2010.

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 for any period presented.

At December 31, 2007, the Company had $246 million notional amount of interest rate derivatives outstanding that related to variable rate tax exempt debt, with net fair value loss of $1.4 million as follows:

Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2007
				(in millions)
$246 million	SIFMA Index	2.96%*	February 2010	$(1.4)

* Hedged using the Securities Industry and Financial Markets Association Municipal Swap Index (SIFMA), (Formerly the Bond Market Association/PSA Municipal Swap Index)

Subsequent to December 31, 2007, the Company entered into $330 million notional amounts of interest rate swaps related to variable rate tax exempt debt, to hedge changes in interest rates beginning in February 2008 through February 2010. The weighted average fixed payment rate on these hedges is 2.49%.

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 2007, 2006, and 2005, the Company settled gains (losses) of $(6.2) million, $18.0 million, and $(21.4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. The effective portions of 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 2007, 2006, and 2005, approximately $(0.8) million, $9.8 million, and $3.5 million, respectively, of pre-tax gains (losses) were reclassified from other comprehensive income to interest expense. For 2008, pre-tax losses of approximately $0.2 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2010 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 $1.6 billion in 2008, $1.6 billion in 2009, and $1.0 billion in 2010. These amounts include $60 million, $50 million, and $42 million in 2008, 2009, and 2010, 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 statutes and 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, 2007, 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, which are subject to price escalation, 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 $136 million over the remaining life of the agreements, which are currently estimated to range up to 9 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, 2007 were as follows:

	Commitments		
	Affiliated	Non-Affiliated	Total
		(in millions)	
2008	$ 50	$ 39	$ 89
2009	50	40	90
2010	13	23	36
2011	-	2	2
2012	-	-	-
2013 and thereafter	-	-	-
Total commitments	$113	$104	$217

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company is constructing certain equipment and has entered into various long-term commitments for the procurement of limestone to be used in such equipment. Contracts are structured with tonnage minimums and maximums in order to account for changes in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.1 million tons equating to approximately $127 million through 2019. Estimated expenditures over the next five years are $2 million in 2008, $3 million in 2009, $11 million in 2010, $14 million in 2011, and $14 million in 2012.

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, 2007. Total estimated minimum long-term commitments at December 31, 2007 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2008	$ 524	$1,180	$ 60
2009	361	999	50
2010	136	679	42
2011	17	573	47
2012	16	586	46
2013 and thereafter	126	1,642	42
Total commitments	$1,180	$5,659	$287

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense totaled $65 million in 2007, $66 million in 2006, and $64 million in 2005.

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 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 $27.7 million in 2007, $30.3 million in 2006, and $27.3 million in 2005. Of these amounts, $20.5 million, $21.5 million, and $17.8 million for 2007, 2006, and 2005, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR. At December 31, 2007, estimated minimum rental commitments for non-cancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2008	$20	$ 6	$26
2009	15	6	21
2010	11	5	16
2011	5	4	9
2012	5	2	7
2013 and thereafter	17	1	18
Total	$73	$24	$97

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 $62.2 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, 2007, 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, 2007, 1,184 current and former employees of the Company participated in the stock option plan. The maximum number of shares of common stock that may be issued under this plan may not exceed 40 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.

The Company's activity in the stock option plan for 2007 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2006	5,895,129	$28.63
Granted	1,195,479	36.42
Exercised	(896,957)	26.07
Cancelled	(7,221)	34.51
Outstanding at December 31, 2007	**6,186,430**	**$30.50**
Exercisable at December 31, 2007	**3,953,015**	**$27.95**

The number of stock options vested and expected to vest in the future, as of December 31, 2007 was not significantly different from the number of stock options outstanding at December 31, 2007 as stated above. As of December 31, 2007, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.4 years and 5.3 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $51.0 million and $42.7 million, respectively.

As of December 31, 2007, 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 10 months.

The total intrinsic value of options exercised during the years ended December 31, 2007, 2006, and 2005 was $9.7 million, $4.9 million, and $21.9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $3.7 million, $1.9 million, and $8.5 million, respectively, for the years ended December 31, 2007, 2006, and 2005.

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. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 31, 2008.

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 $2.3 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 the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 $37 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 month period is $3.2 billion plus such additional amounts NEIL, can recover through reinsurance, indemnity, or other sources.

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 2007 and 2006 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2007	**$1,197**	**$255**	**$115**
June 2007	**1,336**	**311**	**147**
September 2007	**1,635**	**476**	**246**
December 2007	**1,192**	**173**	**72**
March 2006	$1,073	$198	$ 82
June 2006	1,249	258	118
September 2006	1,572	458	238
December 2006	1,121	196	80

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

SELECTED FINANCIAL AND OPERATING DATA 2003-2007

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	2007	2006	2005	2004	2003
Operating Revenues (in thousands)	**$5,359,993**	$5,014,728	$4,647,824	$4,235,991	$3,960,161
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$579,582**	$517,730	$507,895	$481,171	$472,810
Cash Dividends on Common Stock (in thousands)	**$465,000**	$440,600	$409,900	$437,300	$430,200
Return on Average Common Equity (percent)	**13.73**	13.23	13.72	13.53	13.75
Total Assets (in thousands)	**$15,746,625**	$14,655,290	$13,689,907	$12,781,525	$12,099,575
Gross Property Additions (in thousands)	**$1,203,300**	$960,759	$890,062	$786,298	$661,154
Capitalization (in thousands):					
Common stock equity	**$4,410,683**	$4,032,287	$3,792,726	$3,610,204	$3,500,660
Preferred and preference stock	**683,512**	612,407	465,046	465,047	372,512
Mandatorily redeemable preferred securities	-	-	-	-	300,000
Long-term debt	**4,750,196**	4,148,185	3,869,465	4,164,536	3,377,148
Total (excluding amounts due within one year)	**$9,844,391**	$8,792,879	$8,127,237	$8,239,787	$7,550,320
Capitalization Ratios (percent):					
Common stock equity	**44.8**	45.9	46.7	43.8	46.4
Preferred and preference stock	**6.9**	7.0	5.7	5.6	4.9
Mandatorily redeemable preferred securities	-	-	-	-	4.0
Long-term debt	**48.3**	47.1	47.6	50.6	44.7
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
Standard and Poor's	-	-	A+	A	A
Fitch	-	-	AA-	AA-	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	**1,207,883**	1,194,696	1,184,406	1,170,814	1,160,129
Commercial	**216,830**	214,723	212,546	208,547	204,561
Industrial	**5,849**	5,750	5,492	5,260	5,032
Other	**772**	766	759	753	757
Total	**1,431,334**	1,415,935	1,403,203	1,385,374	1,370,479
Employees (year-end)	**6,980**	6,796	6,621	6,745	6,730

	2007	2006	2005	2004	2003
Operating Revenues (in thousands):					
Residential	**$1,833,563**	$1,664,304	$1,476,211	$1,346,669	$1,276,800
Commercial	**1,313,642**	1,172,436	1,062,341	980,771	913,697
Industrial	**1,238,368**	1,140,225	1,065,124	948,528	844,538
Other	**21,383**	18,766	17,745	16,860	16,428
Total retail	**4,406,956**	3,995,731	3,621,421	3,292,828	3,051,463
Wholesale - non-affiliates	**627,047**	634,552	551,408	483,839	487,456
Wholesale - affiliates	**144,089**	216,028	288,956	308,312	277,287
Total revenues from sales of electricity	**5,178,092**	4,846,311	4,461,785	4,084,979	3,816,206
Other revenues	**181,901**	168,417	186,039	151,012	143,955
Total	**$5,359,993**	$5,014,728	$4,647,824	$4,235,991	$3,960,161
Kilowatt-Hour Sales (in thousands):					
Residential	**18,874,039**	18,632,935	18,073,783	17,368,321	16,959,566
Commercial	**14,761,243**	14,355,091	14,061,650	13,822,926	13,451,757
Industrial	**22,805,676**	23,187,328	23,349,769	22,854,399	21,593,519
Other	**200,874**	199,445	198,715	198,253	203,178
Total retail	**56,641,832**	56,374,799	55,683,917	54,243,899	52,208,020
Sales for resale - non-affiliates	**15,769,485**	15,978,465	15,442,728	15,483,420	17,085,376
Sales for resale - affiliates	**3,241,168**	5,145,107	5,735,429	7,233,880	9,422,301
Total	**75,652,485**	77,498,371	76,862,074	76,961,199	78,715,697
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**9.71**	8.93	8.17	7.75	7.53
Commercial	**8.90**	8.17	7.55	7.10	6.79
Industrial	**5.43**	4.92	4.56	4.15	3.91
Total retail	**7.78**	7.09	6.50	6.07	5.84
Wholesale	**4.06**	4.03	3.97	3.49	2.88
Total sales	**6.84**	6.25	5.80	5.31	4.85
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,696**	15,663	15,347	14,894	14,688
Residential Average Annual Revenue Per Customer	**$1,525**	$1,399	$1,253	$1,155	$1,106
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,216	12,216	12,174
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,144**	10,309	9,812	9,556	10,409
Summer	**12,211**	11,744	11,162	10,938	10,462
Annual Load Factor (percent)	**59.4**	61.8	63.2	63.2	64.1
Plant Availability (percent):					
Fossil-steam	**88.21**	89.6	90.5	87.8	85.9
Nuclear	**87.47**	93.3	92.9	88.7	94.7
Source of Energy Supply (percent):					
Coal	**60.9**	60.2	59.5	56.5	56.5
Nuclear	**16.5**	17.4	17.2	16.4	17.0
Hydro	**1.8**	3.8	5.6	5.6	7.0
Gas	**8.7**	7.6	6.8	8.9	7.6
Purchased power -					
From non-affiliates	**1.8**	2.1	3.8	5.4	4.1
From affiliates	**10.3**	8.9	7.1	7.2	7.8
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS

Alabama Power Company 2007 Annual Report

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

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

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

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

James K. Lowder
Chairman,
The Colonial Company

Charles D. McCrary
President and CEO,
Alabama Power Company

Malcolm Portera
Chancellor, The University of Alabama System

Robert D. Powers
President,
The Eufaula Agency, Inc.

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

C. Dowd Ritter
Chairman[1], President and CEO,
Regions Financial Corporation

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

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

James W. Wright
Chairman,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

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

Mark A. Crosswhite [2]
Executive Vice President

C. Alan Martin [3]
Executive Vice President

Steve R. Spencer
Executive Vice President

Gordon G. Martin [4]
Senior Vice President and General 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

Leigh Davis
Vice President - Chief Information Officer

Greg Barker
Vice President

Robert A. Bell
Vice President

Willard L. Bowers
Vice President

Larry R. Grill
Vice President

Gerald L. Johnson
Vice President, Birmingham Division

William B. Johnson
Vice President

Bobby J. Kerley
Vice President

Barbara J. Knight
Vice President

Myrna J. Pittman
Vice President

Donald W. Reese [5]
Vice President

Leslie L. Sanders [6]
Vice President

R. Michael Saxon
Vice President, Southeast Division

Julia H. Segars
Vice President, Eastern Division

Julian H. Smith, Jr.
Vice President

Zeke W. Smith
Vice President

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

Anita Allcorn-Walker
Assistant Comptroller

Ronald Q. Patterson
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, 2007 except as noted below:

[1] Effective 1/08
[2] Elected 2/08
[3] Resigned 2/08
[4] Elected 2/08
[5] Retired 10/07
[6] Elected 10/07

CORPORATE INFORMATION

Alabama Power Company 2007 Annual Report

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

Profile
The Company 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 2007, retail energy sales accounted for 75 percent of the Company's total sales of 76 billion kilowatt-hours.

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

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes and
Trust Preferred Securities
The Bank of New York Mellon
Global Corporate Trust
505 North 20th Street, Suite 950
Birmingham, AL 35203

Registrar, Transfer Agent, and Dividend Paying Agent
All series except the 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 5.30% Series Class A Preferred Stock
BNY Mellon Shareowner Services
480 Washington Blvd., 26th Floor
Jersey City, NJ 07310

Number of Preferred and Preference Shareholders of record as of December 31, 2007 was 1,568.

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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417 North 20th Street
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Legal Counsel
Balch & Bingham LLP
P.O. Box 306
Birmingham, AL 35201

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