2006 *Annual Report*

Gulf Power Company

CONTENTS
Gulf Power Company 2006 Annual Report

SUMMARY

	2006	2005	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,203,914**	$1,083,622	11.1
Operating expenses	**$1,037,242**	$925,345	12.1
Net Income after dividends on preferred and preference stock	**$75,989**	$75,209	1.0
Gross property additions	**$147,086**	$142,583	3.2
Total assets	**$2,340,489**	$2,175,797	7.6
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**11,428,880**	11,238,896	1.7
Sales for resale - non-affiliates	**2,079,165**	2,295,850	(9.4)
Sales for resale - affiliates	**2,937,735**	1,976,368	48.6
Total	**16,445,780**	15,511,114	6.0
Customers served at year-end	**418,892**	408,641	2.5
Peak-hour demand, net *(in megawatts)*	**2,479**	2,433	1.9
Capitalization Ratios *(percent)*:			
Common stock equity	**45.8**	47.3	
Preferred and preference stock	**3.9**	4.2	
Long-term debt payable to affiliated trusts	**3.0**	5.7	
Long-term debt (excluding amounts due within one year)	**47.3**	42.8	
Return on Average Common Equity *(percent)*	**12.29**	12.59	

Letter to Investors
2006 Gulf Power Company Annual Report

The value of electricity

It's great to live in the 21st century. Our age is one of unprecedented technological advances in medicine, information transfer, communications and transportation. And our homes are filled today with electronic appliances and computer conveniences which keep us comfortable, save us time, inform us and entertain us. And most of these appliances run for hours for just a few cents.

One constant amidst all this technology is electricity – dependable and affordable electricity that helps keep our standard of living the highest in the world.

At Gulf Power Company we are committed to providing great customer service, with reliable electricity at affordable prices. Our prices remain among the lowest in the nation and the lowest in Florida among major investor-owned utilities.

Of course, we know this isn't enough. We strongly believe in environmental responsibility and we have a track record to match. Since the 1990s, demand for electricity in our area has increased 20 percent, but Gulf Power Company has reduced overall emissions from its power plants by more than 70 percent. We have invested in an on-site mercury reduction test facility at Pensacola's Plant Crist and we continue to study alternative fuels and coal gasification.

Our performance in 2006 reflects our growing area and our commitment to superior performance. Kilowatt-hour sales in 2006 were up six percent from 2005. Net income after dividends on preferred and preference stock was $76 million – up 1.04 percent from 2005, and our return on average common equity was 12.29 percent. Meanwhile, we added 10,253 customers in 2006, bringing us to 418,890 total customers in Northwest Florida.

In 2007, we will continue to work to meet the growing demands of Northwest Florida for reliable, affordable and environmentally responsible energy.

Susan N. Story,
President and Chief Executive Officer
April 9, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages 21 to 44) present fairly, in all material respects, the financial position of Gulf Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

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

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and storm restoration costs. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida Public Service Commission (PSC) issued an order (2005 Order) that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through a two-year surcharge that began in April 2005. In July 2006, the Florida PSC issued an order (2006 Order) approving another stipulation and settlement between the Company and several consumer groups and thereby authorized an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009. See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 415,000 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 plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected economic conditions. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

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

Key Performance Indicator	2006 Target Performance	2006 Actual Performance
Customer Satisfaction	Top quartile performance in customer surveys	**Top quartile**
Peak Season EFOR	3.00%	**2.57%**
Net Income	$76.1 million	**$76.0 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2006 net income after dividends on preferred and preference stock was $76.0 million, an increase of $0.8 million from the previous year. In 2005, earnings were $75.2 million, an increase of $7.0 million from the previous year. In 2004, earnings were $68.2 million, a decrease of $0.8 million from the previous year. The increase in earnings in 2006 is due primarily to higher operating revenues partially offset by higher operating expenses, higher financing costs, and increases in depreciation expense. The increase in earnings in 2005 was due primarily to higher retail sales and lower non-fuel operating expenses, excluding expenses related to Hurricane Ivan storm damage, which are offset by revenues and do not affect earnings. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein. The decrease in earnings in 2004 was due primarily to higher operating expenses related to replenishing property damage reserves and increased expenses related to employee benefits.

RESULTS OF OPERATIONS

A condensed statement of income is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
	(in thousands)			
Operating revenues	**$ 1,203,914**	**$ 120,292**	$ 123,491	$ 82,434
Fuel	**534,921**	**119,132**	48,634	50,652
Purchased power	**73,824**	**(24,573)**	32,500	15,740
Other operation and maintenance	**259,519**	**9,749**	20,058	19,012
Depreciation and amortization	**89,170**	**4,168**	2,203	477
Taxes other than income taxes	**79,808**	**3,421**	6,531	3,741
Total operating expenses	**1,037,242**	**111,897**	109,926	89,622
Operating income	**166,672**	**8,395**	13,565	(7,188)
Total other income and (expense)	**(42,090)**	**(4,764)**	(749)	5,219
Income taxes	**45,293**	**312**	5,286	(1,182)
Net Income	**79,289**	**3,319**	7,530	(787)
Dividends on Preferred and Preference Stock	**3,300**	**2,539**	544	-
Net Income after Dividends on Preferred and Preference Stock	**$ 75,989**	**$ 780**	$ 6,986	$ (787)

Revenues

Operating revenues increased in 2006 when compared to 2005 and 2004. The following table summarizes the changes in operating revenues for the past three years:

	Amount		
	2006	2005	2004
	(in thousands)		
Retail -- prior year	**$ 864,859**	$ 736,870	$ 699,174
Change in --			
Base rates	**-**	-	-
Sales growth	**2,473**	11,568	4,896
Weather	**2,443**	(4,223)	3,313
Fuel cost recovery and other	**82,263**	120,644	29,487
Retail -- current year	**952,038**	864,859	736,870
Sales for resale --			
Non-affiliates	**87,142**	84,346	73,537
Affiliates	**118,097**	91,352	110,264
Total sales for resale	**205,239**	175,698	183,801
Other operating revenues	**46,637**	43,065	39,460
Total operating revenues	**$ 1,203,914**	$ 1,083,622	$ 960,131
Percent change	**11.1%**	12.9%	9.4%

Retail revenues increased $87 million, or 10.1 percent, in 2006, $128.0 million, or 17.4 percent, in 2005, and $37.7 million, or 5.4 percent, in 2004. The significant factors driving these changes are shown in the table above.

Fuel and other cost recovery includes recovery provisions for fuel expenses and the energy component of purchased power costs, energy conservation costs, purchased power capacity costs, and environmental compliance costs. Annually, the Company petitions for recovery of projected costs including any true-up amount from prior periods, and approved rates are implemented each January. Other cost recovery also includes revenues related to the recovery of incurred costs for storm damage activity as approved by the Florida PSC. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues," "Property Damage Reserve," and "Environmental Cost Recovery" and Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" and "– Storm Damage Cost Recovery" for additional information.

Total sales for resale were $205.2 million in 2006, an increase of $29.5 million, or 16.8 percent, compared to 2005, primarily due to increased energy sales to affiliates to serve their territorial energy requirements. Total sales for resale were $175.7 million in 2005, a decrease of $8.1 million, or 4.4 percent, compared to 2004, primarily due to lower energy sales to affiliates resulting from decreases in the Company's available generation as a result of outages at Plants Crist and Smith. Total sales for resale were $183.8 million in 2004, an increase of $43.8 million, or 31.3 percent, compared to 2003, primarily due to energy sales to affiliates at a higher unit cost resulting from higher incremental fuel prices.

Revenue from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). 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 revenues through the Company's fuel cost recovery clause.

Sales for resale to non-affiliates are predominantly unit power sales under long-term contracts to other Florida utilities. Revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components under these unit power sales contracts were as follows:

	2006	2005	2004
	(in thousands)		
Unit Power --			
Capacity	**$ 21,477**	$ 20,852	$ 18,780
Energy	**34,597**	33,206	29,360
Total	**$ 56,074**	$ 54,058	$ 48,140

Other operating revenues increased $3.6 million, $3.6 million, and $1.0 million in 2006, 2005, and 2004, respectively, primarily due to an increase in franchise fees, which are proportional to changes in revenue.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. Kilowatt-hour (KWH) sales for 2006 and the percent changes by year were as follows:

	KWH 2006	Percent Change 2006	2005	2004
	(in millions)			
Residential	**5,426**	**2.0%**	2.0%	2.2%
Commercial	**3,843**	**2.9**	1.1	2.2
Industrial	**2,136**	**(1.1)**	2.3	(1.6)
Other	**24**	**5.1**	0.7	0.4
Total retail	**11,429**	**1.7**	1.7	1.5
Sales for resale				
Non-affiliates	**2,079**	**(9.4)**	1.7	(9.9)
Affiliates	**2,938**	**48.6**	(36.8)	28.1
Total	**16,446**	**6.0**	(5.6)	3.8

Residential energy sales increased 2.0 percent in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth. Residential energy sales increased 2.0 percent in 2005, compared to 2004, primarily due to customer growth offset by unfavorable weather conditions. Residential energy sales increased 2.2 percent in 2004, compared to 2003, due to more favorable weather conditions and customer growth.

Commercial energy sales increased 2.9 percent in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth. Commercial energy sales increased 1.1 percent in 2005, compared to 2004, primarily due to customer growth offset by unfavorable weather conditions. Commercial energy sales increased 2.2 percent in 2004, compared to 2003, primarily due to more favorable weather conditions and customer growth.

Industrial energy sales decreased 1.1 percent in 2006, compared to 2005, due to reduced demand for and production of building materials and a conversion project by a major paper manufacturer. Industrial energy sales increased 2.3 percent in 2005, compared to 2004, primarily due to additional sales to customers with gas-fired cogeneration resulting from high natural gas prices. Industrial energy sales decreased 1.6 percent in 2004, compared to 2003, primarily due to the short-term outage experienced as a result of Hurricane Ivan in September 2004.

Sales for resale to non-affiliates decreased 9.4 percent in 2006, increased 1.7 percent in 2005, and decreased 9.9 percent in 2004, each compared to the prior year primarily as a result of fluctuations in the fuel cost to produce energy sold to non-affiliated utilities under both long-term and short-term contracts. The degree to which oil and natural gas prices, which are the primary fuel sources for these customers, differ from the Company's fuel costs will influence these changes in sales. The fluctuations in sales have a minimal effect on earnings because the energy is generally sold at variable cost.

Sales for resale to affiliates increased 48.6 percent in 2006 compared to 2005, primarily due to increased territorial energy requirements of affiliates. Sales for resale to affiliates decreased 36.8 percent in 2005 compared to 2004, due to decreases in the Company's available generation as a result of outages at Plants Crist and Smith. Sales for resale increased 28.1 percent in 2004 compared to 2003, primarily to serve affiliates' territorial energy requirements.

Expenses

Fuel and Purchased Power

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generation resources. Details of the Company's amount and sources of generation, the average cost of fuel per net KWH generated, and the average costs of purchased power were as follows:

	2006	2005	2004
Total generation (millions of KWH)	**16,349**	15,024	15,841
Total purchased power (millions of KWH)	**876**	1,172	1,326
Sources of generation (percent) –			
Coal	**87%**	86%	84%
Gas	**13**	14	16
Cost of fuel, generation (cents per net KWH) –			
Coal	**2.68**	2.16	1.83
Gas	**7.24**	6.48	4.95
Average cost of fuel, generated (cents per net KWH)	**3.27**	2.77	2.32
Average cost of purchased power (cents per net KWH)	**8.43**	8.39	4.97

Fuel expense was $535 million in 2006, an increase of $119.1 million, or 28.7 percent, above the prior year costs. This increase was the result of an $82.4 million increase in the cost of fuel and a $36.7 million increase related to total KWH generated. Fuel expense was $416 million in 2005, an increase of $48.6 million, or 13.2 percent, above the prior year costs. This increase was the result of a $67.5 million increase in the cost of fuel and an $18.9 million decrease related to total KWH generated. Fuel expense was $367 million in 2004, an increase of $50.7 million, or 16 percent, above the prior year costs. This increase was the result of an $32.7 million increase in the cost of fuel and a $18 million increase related to total KWH generated.

Purchased power expense was $73.8 million in 2006, a decrease of $24.6 million, or 25.0 percent, below the prior year costs. This decrease was the result of a $24.9 million decrease in total KWH purchased and a $0.3 million increase resulting from the higher average cost per net KWH. Purchased power expense was $98.4 million in 2005, an increase of $32.5 million, or 49.3 percent, above the prior year costs. This increase was the result of a $7.6 million decrease in total KWH purchased and a $40.1 million increase resulting from the higher average cost per net KWH. Purchased power expense was $65.9 million in 2004, an increase of $15.7 million, or 31.4 percent, above the prior year costs. This increase was the result of a $6.6 million decrease in total KWH purchased and a $22.3 million increase resulting from the higher average cost per net KWH.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements for additional information.

Other Operations and Maintenance

In 2006, other operations and maintenance expense increased $9.7 million, or 3.9 percent, compared to the prior year primarily due to a $4.2 million increase in the recovery of incurred costs for storm damage activity as approved by the Florida PSC, a $1.9 million increase in employee benefit expenses, and a $1.1 million increase in property insurance costs. In 2005, other operations and maintenance expense increased $20.1 million, or 8.7 percent, compared to the prior year primarily due to the recovery of $20.4 million in Hurricane Ivan restoration costs as approved by the Florida PSC. Since these storm damage expenses are recognized as revenues are recorded, there is no impact on net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information. In 2004, other operations and maintenance expense increased $19.0 million, or 9.0 percent, compared to the prior year primarily due to increases of $7.9 million in the property damage reserve, $2.9 million in the accrued expenses for uninsured litigation and workers compensation claims, $3.4 million for employee benefit expenses, and $2.5 million for production expenses. See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information on the property damage reserve.

Depreciation and Amortization

Depreciation and amortization expense increased $4.2 million, or 4.9 percent, in 2006 compared to the prior year primarily due to the construction of environmental control projects at Plants Crist and Daniel that were placed in service in 2005. Depreciation and amortization expense increased $2.2 million, or 2.7 percent, in 2005 compared to the prior year primarily due to the completion of environmental control projects at Plant Crist Unit 7. Depreciation and amortization expense remained relatively flat in 2004 compared to the prior year due to no significant change in depreciable assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $3.4 million, or 4.5 percent, in 2006, $6.5 million, or 9.3 percent, in 2005, and $3.7 million, or 5.7 percent, in 2004 primarily due to increases in franchise and gross receipts taxes, which are directly related to the increase in retail revenues.

Other Income and (Expense)

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) decreased $0.8 million, or 68.9 percent, in 2006 compared to the prior year primarily due to the completion of an environmental control project at Plant Crist Unit 7. AFUDC decreased $0.7 million, or 37.1 percent, in 2005 and increased $1.1 million, or 160.7 percent, in 2004 compared to the prior year primarily due to the construction and completion of an environmental control project at Plant Crist Unit 7. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein and Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest Income

Interest income increased $1.4 million, or 37.4 percent, in 2006 compared to the prior year primarily due to interest received related to the recovery of financing costs associated with the fuel clause and incurred costs for storm damage activity as approved by the Florida PSC. Interest income increased $2.6 million, or

210.9 percent, in 2005 compared to the prior year primarily due to interest received from a tax refund resulting from Hurricane Ivan and interest received related to the recovery of financing costs associated with Hurricane Ivan. See FUTURE EARNINGS POTENTIAL – "Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information. Interest income remained relatively flat in 2004 compared to the prior year.

Interest Expense

Interest expense, net of amounts capitalized increased $3.9 million, or 10.9 percent, in 2006 compared to the prior year as the result of higher interest rates on variable rate pollution control bonds, increased levels of short-term borrowings at higher interest rates, and the issuance of $60 million in senior notes in August 2005. These increases were partially offset by the maturity of a $100 million bank note in October 2005 and the extinguishment of $30 million aggregate principal amount of first mortgage bonds in 2005. Interest expense increased $4.2 million, or 13.5 percent, in 2005 compared to the prior year as the result of higher interest rates on variable rate pollution control bonds and an increase in outstanding short-term indebtedness as a result of hurricane-related costs. Interest expense decreased $2.1 million, or 5.5 percent, in 2004 compared to the prior year primarily as the result of refinancing higher cost securities.

Other Deductions

Other deductions increased $1.5 million, or 52.9 percent, in 2006, decreased $1.4 million, or 32.2 percent, in 2005, and $1.5 million, or 25.7 percent, in 2004 compared to the prior years as a result of changes in charitable contributions.

Effects of Inflation

The Company is subject to rate regulation based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing environmental and fuel 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.

Environmental Matters

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

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit partially owned by the Company at Plant Scherer. See Note 4 to the financial statements for information on the Company's ownership interest in Plant Scherer Unit 3. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notices of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled.

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

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, the Company had invested approximately $299 million in capital projects to comply with these requirements, with annual totals of $46 million, $45 million, and $67 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $171 million, $378 million, and $300 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

The Florida Legislature has adopted legislation that allows a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $153.4 million 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 2006, the Company completed implementation of the terms of a 2002 agreement with the State of Florida to help ensure attainment of the ozone standard in the Pensacola, Florida area. The conditions of the agreement, which required installing additional controls on certain units and retiring three older units at a plant near Pensacola, totaled approximately $133.8 million, and have been approved under the Company's environmental cost recovery clause.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Macon, Georgia, where Plant Scherer is located, was designated as nonattainment under the eight-hour ozone standard. No area within the Company's service area was designated as nonattainment under the eight-hour ozone standard. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, are currently required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

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

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

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

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

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

Water Quality

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

One facility within the Southern Company system is retrofitting a closed-loop recirculating cooling tower under the Clean Water Act to cool water prior to discharge and similar projects are being considered at other facilities.

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 clean up costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

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

FERC Matters

Market-Based Rate Authority

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

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $3 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

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

Intercompany Interchange Contract

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

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

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

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

Transmission

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

PSC Matters

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Florida PSC. At December 31, 2006 and 2005, the under recovered balance was $77.5 million and $31.6 million, respectively, primarily due to increased costs for coal in 2006 and increased costs for coal and natural gas in 2005. The Company continuously monitors the under recovered fuel cost balance in light of these higher fuel costs. If the projected fuel revenue over or under recovery exceeds 10 percent of the projected fuel costs for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

In November 2006, the Florida PSC approved an increase of approximately 28 percent in the fuel factor for retail customers, effective with billings beginning January 2007. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, any change in the billing factor would have no significant effect on the Company's revenues or net income, but would impact annual cash flow.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida PSC issued the 2005 Order that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through the two-year surcharge that began in April 2005.

In July 2006, the Florida PSC issued the 2006 Order approving another stipulation and settlement between the Company and several consumer groups that resolved all matters relating to the Company's request for recovery of incurred costs for storm-recovery activities related to the 2005 storms and the replenishment of the Company's property damage reserve. The 2006 Order provides for an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009.

According to the 2006 Order, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by the Company through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve.

The annual accrual to the reserve of $3.5 million and the Company's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. The Company made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of the 2005 Order regarding Hurricane Ivan costs that established the existing surcharge, the Company agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the 2006 Order do not alter or affect that portion of the prior agreement.

According to the 2006 Order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism.

See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Storm Damage Cost Recovery," respectively, for additional information.

Other Matters

In 2004, Georgia Power and the Company entered into PPAs with Florida Power & Light Company (FP&L) and Progress Energy Florida. Under the agreements, Georgia Power and the Company will provide FP&L and Progress Energy Florida with 165 megawatts and 74 megawatts, respectively, of capacity annually from the jointly owned Plant Scherer Unit 3 for the period from June 2010 through December 2015. The contracts provide for fixed capacity payments and variable energy payments based on actual energy delivered. The Florida PSC approved the contracts in 2005.

Also in 2004, Georgia Power and the Company entered into a PPA with Flint Electric Membership Corporation. Under the agreement, Georgia Power and the Company will provide Flint Electric Membership Corporation with 75 megawatts of capacity annually from the jointly owned Plant Scherer Unit 3 for the period from June 2010 through December 2019. The contract provides for fixed capacity payments and variable energy payments based on actual energy delivered.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Florida 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 and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

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

New Accounting Standards

Stock Options

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

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $23.5 million with respect to its overfunded defined benefit plan and additional liabilities of $2.5 million and $12.9 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plan. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

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

Income Taxes

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

Fair Value Measurement

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

Fair Value Option

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Net cash flow from operations totaled $143.4 million, $152.7 million, and $144.5 million for 2006, 2005, and 2004, respectively. The $9.3 million decrease in net cash flows in 2006 is due primarily to increased payments related to income taxes and fuel. The $8.2 million increase in net cash flows in 2005 was due primarily to the recovery of Hurricane Ivan restoration costs. The $46.8 million decrease in net cash flows in 2004 was primarily due to payments related to storm damage from Hurricane Ivan. Gross property additions were $147.1 million in 2006. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities. See the statements of cash flows for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.1 percent in 2006, 43.0 percent in 2005, and 43.2 percent in 2004. See Note 6 to the financial statements for additional information.

The Company has received investment grade ratings from the major rating agencies with respect to its debt, preferred securities, 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, securities issuances, term loans, and short-term indebtedness. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2007, the Company had approximately $7.5 million of cash and cash equivalents, along with $120 million of unused committed lines of credit with banks to meet its short-term cash needs. These bank credit arrangements will expire during 2007. The Company plans to renew these lines of credit during 2007. In addition, the Company has substantial cash flow from operating activities and access to the capital markets including commercial paper programs to meet liquidity needs. 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. There is no cross affiliate credit support. At December 31, 2006, the Company had $80.4 million in commercial paper notes and $40.0 million in bank notes outstanding.

Financing Activities

In December 2006, the Company issued $110 million of senior notes. A portion of the proceeds of this issuance was used to redeem $30.9 million of long-term debt payable to affiliated trusts. The remainder of the funds from the sale of senior notes was used for general corporate purposes, including the Company's continuous construction program.

On January 19, 2007, the Company issued to Southern Company 800,000 shares of the Company's common stock, without par value, and realized proceeds of $80 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3, or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2006, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $23.1 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $46.3 million.

The Company, along with all members of the Southern Company power pool, is party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for Alabama Power and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price Risk

Due to cost-based rate regulation, 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 residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for natural gas purchases. The Company has implemented a fuel-hedging program with the approval of the Florida PSC.

The weighted average interest rate on $144.6 million variable long-term debt that has not been hedged at January 1, 2007 was 3.73 percent. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $1.4 million at January 1, 2007. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

The changes in fair value of energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in thousands)	
Contracts beginning of year	**$ 11,526**	$ 317
Contracts realized or settled	**8,363**	(15,023)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**(27,075)**	26,232
Contracts end of year	**$ (7,186)**	$ 11,526

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

	Source of 2006 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	2007	2008-2009
	(in thousands)		
Actively quoted	$ (7,324)	$ (6,641)	$ (683)
External sources	138	138	-
Models and other methods	-	-	-
Contracts end of year	$ (7,186)	$ (6,503)	$ (683)

Unrealized gains and losses from mark-to-market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery clause. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$ (7,186)
Net income	-
Total fair value	$ (7,186)

Unrealized (losses) recognized in income were not material in any year presented.

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $278 million in 2007, $458 million in 2008, and $395 million in 2009. The construction program also includes $171 million in 2007, $378 million in 2008, and $300 million in 2009 for environmental expenditures. Actual construction costs may vary from these estimates because of changes in such factors as: business conditions; environmental 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.

The Company does not have any new generating capacity under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, is ongoing.

The Company has entered into two PPAs, one of which is with Southern Power, for a total of approximately 487 megawatts annually from June 2009 through May 2014. The PPAs are the result of a competitive request for proposals process initiated by the Company in January 2006 to address the anticipated need for additional capacity beginning in 2009. These PPAs are both subject to approval by the Florida PSC for purposes of cost recovery through the Company's purchased power capacity clause, and the PPA with Southern Power is also subject to FERC approval.

As discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

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

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in thousands)		
Long-term debt[a] --					
Principal	$ -	$ -	$ -	$ 703,793	$ 703,793
Interest	34,924	69,848	69,848	563,334	737,954
Other derivative obligations[b]	7,193	838	-	-	8,031
Preference stock dividends[c]	3,300	6,600	6,600	-	16,500
Operating leases	4,380	5,635	2,661	3,574	16,250
Purchase commitments[d] –					
Capital[e]	277,958	852,811	-	-	1,130,769
Coal	281,401	310,220	70,764	-	662,385
Natural gas[f]	117,726	156,346	63,275	189,106	526,453
Purchased power	-	23,832	53,672	57,915	135,419
Long-term service agreements	5,940	12,821	16,735	39,419	74,915
Postretirement benefits[g]	60,000	120,000	-	-	180,000
Total	$ 792,822	$ 1,558,951	$ 283,555	$ 1,557,141	$ 4,192,469

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization.

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

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

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expense for the last three years were $260 million, $250 million, and $230 million, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

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

(g) The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's storm damage cost recovery and repairs, retail rates, environmental regulations and expenditures, access to sources of capital, the Company's projections for postretirement benefit trust contributions, financing activities, impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against the Company and FERC matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 952,038**	$ 864,859	$ 736,870
Sales for resale --			
Non-affiliates	**87,142**	84,346	73,537
Affiliates	**118,097**	91,352	110,264
Other revenues	**46,637**	43,065	39,460
Total operating revenues	**1,203,914**	1,083,622	960,131
Operating Expenses:			
Fuel	**534,921**	415,789	367,155
Purchased power --			
Non-affiliates	**16,288**	29,995	30,720
Affiliates	**57,536**	68,402	35,177
Other operations	**192,375**	176,620	160,635
Maintenance	**67,144**	73,150	69,077
Depreciation and amortization	**89,170**	85,002	82,799
Taxes other than income taxes	**79,808**	76,387	69,856
Total operating expenses	**1,037,242**	925,345	815,419
Operating Income	**166,672**	158,277	144,712
Other Income and (Expense):			
Interest income	**5,228**	3,804	1,224
Interest expense, net of amounts capitalized	**(39,619)**	(35,727)	(31,482)
Interest expense to affiliate trusts	**(4,514)**	(4,590)	(3,443)
Distributions on mandatorily redeemable preferred securities	**-**	-	(1,113)
Other income (expense), net	**(3,185)**	(813)	(1,763)
Total other income and (expense)	**(42,090)**	(37,326)	(36,577)
Earnings Before Income Taxes	**124,582**	120,951	108,135
Income taxes	**45,293**	44,981	39,695
Net Income	**79,289**	75,970	68,440
Dividends on Preferred and Preference Stock	**3,300**	761	217
Net Income After Dividends on Preferred and Preference Stock	**$ 75,989**	$ 75,209	$ 68,223

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 79,289**	$ 75,970	$ 68,440
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**94,466**	90,890	88,772
Deferred income taxes	**1,170**	33,161	46,255
Pension, postretirement, and other employee benefits	**3,319**	375	(895)
Stock option expense	**1,005**	-	-
Tax benefit of stock options	**211**	3,502	3,063
Hedge settlements	**(5,399)**	-	-
Other, net	**6,931**	3,958	11,402
Changes in certain current assets and liabilities --			
Receivables	**(36,795)**	(46,248)	543
Fossil fuel stock	**(31,297)**	(11,740)	2,355
Materials and supplies	**(2,330)**	3,785	(831)
Prepaid income taxes	**(7,060)**	31,898	(32,343)
Property damage cost recovery	**24,544**	20,045	-
Other current assets	**(955)**	3,453	2,721
Accounts payable	**13,876**	(72,532)	(51,876)
Accrued taxes	**(455)**	6,847	629
Accrued compensation	**(3,251)**	311	1,946
Other current liabilities	**6,165**	9,011	4,325
Net cash provided from operating activities	**143,434**	152,686	144,506
Investing Activities:			
Property additions	**(154,377)**	(143,171)	(148,765)
Cost of removal net of salvage	**(4,564)**	(8,504)	(10,259)
Construction payables	**3,309**	(8,806)	13,682
Other	**(8,779)**	(440)	8,952
Net cash used for investing activities	**(164,411)**	(160,921)	(136,390)
Financing Activities:			
Increase in notes payable, net	**30,981**	39,465	12,334
Proceeds --			
Senior notes	**110,000**	60,000	110,000
Other long-term debt	**-**	-	100,000
Preferred and preference stock	**-**	55,000	-
Gross excess tax benefit of stock options	**423**	-	-
Capital contributions from parent company	**26,140**	(94)	29,481
Redemptions --			
Pollution control bonds	**(12,075)**	-	-
First mortgage bonds	**(25,000)**	(30,000)	-
Senior notes	**-**	-	(125,000)
Other long-term debt	**-**	(100,000)	-
Preferred and preference stock	**-**	(4,236)	-
Long-term debt to affiliate trust	**(30,928)**	-	-
Payment of preferred and preference stock dividends	**(3,300)**	(761)	(217)
Payment of common stock dividends	**(70,300)**	(68,400)	(70,000)
Other	**(1,285)**	(3,721)	(2,433)
Net cash provided from (used for) financing activities	**24,656**	(52,747)	54,165
Net Change in Cash and Cash Equivalents	**3,679**	(60,982)	62,281
Cash and Cash Equivalents at Beginning of Year	**3,847**	64,829	2,548
Cash and Cash Equivalents at End of Year	**$ 7,526**	$ 3,847	$ 64,829
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $160, $515, and $819 capitalized, respectively)	**$ 37,297**	$ 35,786	$ 28,796
Income taxes (net of refunds)	**54,533**	(27,912)	24,130

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

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

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 7,526**	$ 3,847
Receivables --		
Customer accounts receivable	**56,489**	51,567
Unbilled revenues	**38,287**	39,951
Under recovered regulatory clause revenues	**79,235**	33,205
Other accounts and notes receivable	**9,015**	10,533
Affiliated companies	**15,302**	24,001
Accumulated provision for uncollectible accounts	**(1,279)**	(1,134)
Fossil fuel stock, at average cost	**76,036**	44,740
Materials and supplies, at average cost	**35,306**	32,976
Property damage cost recovery	**28,771**	28,744
Other regulatory assets	**15,977**	9,895
Other	**14,259**	19,636
Total current assets	**374,924**	297,961
Property, Plant, and Equipment:		
In service	**2,574,517**	2,502,057
Less accumulated provision for depreciation	**901,564**	865,989
	1,672,953	1,636,068
Construction work in progress	**62,815**	28,177
Total property, plant, and equipment	**1,735,768**	1,664,245
Other Property and Investments	**14,846**	6,736
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**17,148**	17,379
Prepaid pension costs	**69,895**	46,374
Other regulatory assets	**110,077**	123,258
Other	**17,831**	19,844
Total deferred charges and other assets	**214,951**	206,855
Total Assets	**$ 2,340,489**	$ 2,175,797

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

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

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ -**	$ 37,075
Notes payable	**120,446**	89,465
Accounts payable --		
Affiliated	**44,375**	36,717
Other	**49,979**	44,139
Customer deposits	**21,363**	18,834
Accrued taxes --		
Income taxes	**29,771**	12,823
Other	**15,033**	11,689
Accrued interest	**7,645**	7,713
Accrued compensation	**16,932**	20,336
Other regulatory liabilities	**9,029**	15,671
Other	**30,975**	21,844
Total current liabilities	**345,548**	316,306
Long-term Debt (See accompanying statements)	**654,860**	544,388
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	**41,238**	72,166
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**237,862**	256,490
Accumulated deferred investment tax credits	**14,721**	16,569
Employee benefit obligations	**73,922**	56,235
Other cost of removal obligations	**165,410**	153,665
Other regulatory liabilities	**46,485**	26,795
Other	**72,533**	76,948
Total deferred credits and other liabilities	**610,933**	586,702
Total Liabilities	**1,652,579**	1,519,562
Preferred and Preference Stock (See accompanying statements)	**53,887**	53,891
Common Stockholder's Equity (See accompanying statements)	**634,023**	602,344
Total Liabilities and Stockholder's Equity	**$ 2,340,489**	$ 2,175,797
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2006 and 2005
Gulf Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long Term Debt:				
First mortgage bonds --				
6.50% due November 1, 2006	**$ -**	$ 25,000		
Total first mortgage bonds	**-**	25,000		
Long-term notes payable --				
4.35% to 5.88% due 2013-2044	**505,000**	395,000		
Total long-term notes payable	**505,000**	395,000		
Other long-term debt --				
Pollution control revenue bonds --				
5.25% due April 1, 2006	**-**	12,075		
4.80% due September 1, 2028	**13,000**	13,000		
Variable rates (3.53% to 4.04% at 1/1/07) due 2022-2037	**144,555**	144,555		
Total other long-term debt	**157,555**	169,630		
Unamortized debt premium (discount), net	**(7,695)**	(8,167)		
Total long-term debt (annual interest requirement -- $32.6 million)	**654,860**	581,463		
Less amount due within one year	**-**	37,075		
Long-term debt excluding amount due within one year	**654,860**	544,388	**47.3%**	42.8%
Long-term Debt Payable to Affiliated Trusts:				
5.6% to 7.38% due 2041 through 2042 (annual interest requirement -- $2.3 million)	**41,238**	72,166	**3.0**	5.7
Preferred and Preference Stock:				
Authorized - 2006: 20,000,000 shares--preferred stock				
- 2006: 10,000,000 shares--preference stock				
- 2005: 20,000,000 shares--preferred stock				
- 2005: 10,000,000 shares--preference stock				
Outstanding - $100 par or stated value -- 6% preference stock	**53,887**	53,891		
- 2006: 550,000 shares (non-cumulative)				
- 2005: 550,000 shares (non-cumulative)				
Total preferred and preference stock (annual dividend requirement -- $3.3 million)	**53,887**	53,891	**3.9**	4.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 2006: 20,000,000 shares				
- 2005: 10,000,000 shares				
Outstanding - 2006: 992,717 shares				
- 2005: 992,717 shares	**38,060**	38,060		
Paid-in capital	**428,592**	400,815		
Retained earnings	**171,968**	166,279		
Accumulated other comprehensive income (loss)	**(4,597)**	(2,810)		
Total common stockholder's equity	**634,023**	602,344	**45.8**	47.3
Total Capitalization	**$ 1,384,008**	$ 1,272,789	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$ 38,060	$ 364,864	$ 161,208	$ (2,774)	$ 561,358
Net income after dividends on preferred stock	-	-	68,223	-	68,223
Capital contributions from parent company	-	32,544	-	-	32,544
Other comprehensive income (loss)	-	-	-	(91)	(91)
Cash dividends on common stock	-	-	(70,000)	-	(70,000)
Other	-	(12)	150	-	138
Balance at December 31, 2004	38,060	397,396	159,581	(2,865)	592,172
Net income after dividends on preferred stock	-	-	75,209	-	75,209
Capital contributions from parent company	-	3,408	-	-	3,408
Other comprehensive income (loss)	-	-	-	55	55
Cash dividends on common stock	-	-	(68,400)	-	(68,400)
Other	-	11	(111)	-	(100)
Balance at December 31, 2005	**38,060**	**400,815**	**166,279**	**(2,810)**	**602,344**
Net income after dividends on preferred and preference stock	**-**	**-**	**75,989**	**-**	**75,989**
Capital contributions from parent company	**-**	**27,777**	**-**	**-**	**27,777**
Other comprehensive income (loss)	**-**	**-**	**-**	**(3,112)**	**(3,112)**
Adjustment to initially apply FASB Statement No. 158, net of tax	**-**	**-**	**-**	**1,325**	**1,325**
Cash dividends on common stock	**-**	**-**	**(70,300)**	**-**	**(70,300)**
Balance at December 31, 2006	**$ 38,060**	**$ 428,592**	**$ 171,968**	**$ (4,597)**	**$ 634,023**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred and preference stock	**$ 75,989**	$ 75,209	$ 68,223
Other comprehensive income (loss):			
Changes in additional minimum pension liability, net of tax of $(13), $(91) and $(184), respectively	**(19)**	(146)	(292)
Change in fair value of marketable securities, net of tax of $-, $- and $35, respectively	**-**	-	56
Changes in fair value of qualifying hedges, net of tax of $(2,082), $- and $-, respectively	**(3,317)**	-	-
Less: Reclassification adjustment for amounts included in net income, net of tax of $140, $126 and $91, respectively	**224**	201	145
Total other comprehensive income (loss)	**(3,112)**	55	(91)
Comprehensive Income	**$ 72,877**	$ 75,264	$ 68,132

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power, Georgia Power, the Company, and Mississippi Power are vertically integrated utilities providing electric service in four Southeastern states. The Company provides retail service to customers in northwest Florida 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 the subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. On January 4, 2006, Southern Company completed the sale of substantially all of the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

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

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $59 million, $54 million, and $56 million during 2006, 2005, and 2004, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.0 million, $4.3 million, and $6.8 million and Mississippi Power $19.7 million, $19.5 million, and $17.4 million in 2006, 2005, and 2004, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced in 2004 and 2005, assistance provided to aid in storm restoration, including Company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm restoration provided to Mississippi Power was $0.2 million and $11.1 million in 2006 and 2005, respectively. The Company received storm restoration assistance from other Southern Company subsidiaries totaling $5.8 million and $12.7 million in 2005 and 2004, respectively. 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.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2006	2005	Note
	(in thousands)		
Environmental remediation	**$ 57,230**	$ 58,235	(a)
Loss on reacquired debt	**18,584**	19,433	(b)
Vacation pay	**5,795**	5,662	(c)
Deferred income tax charges	**17,148**	17,379	(d)
Fuel-hedging assets	**8,031**	2,411	(e)
Underfunded retiree benefit plans	**17,968**	-	(h)
Other assets	**3,319**	3,374	(f)
Under recovered regulatory clause revenues	**77,480**	31,634	(f)
Property damage reserve	**45,654**	74,352	(g)
Asset retirement obligations	**(3,313)**	(640)	(d)
Other cost of removal obligations	**(165,410)**	(153,665)	(d)
Deferred income tax credits	**(17,935)**	(20,627)	(d)
Fuel-hedging liabilities	**(845)**	(13,950)	(e)
Over recovered regulatory clause revenues	**(8,139)**	(5,333)	(f)
Other liabilities	**(1,804)**	(1,916)	(f)
Overfunded retiree benefit plans	**(23,478)**	-	(h)
Total	**$ 30,285**	$ 16,349	

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

(a) Recovered through the environmental cost recovery clause when the expense is incurred.

(b) Recovered over the remaining life of the original issue, which may range up to 40 years.

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

(d) 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.

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

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

(g) Recorded and recovered or amortized as approved by the Florida PSC. Storm cost recovery surcharge ends in June 2009.

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

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

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. The Company's retail electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company is required to notify the Florida PSC if the projected fuel revenue over or under recovery exceeds 10 percent of the projected fuel costs for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance 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. Annually, the Company petitions for recovery of projected costs including any true-up amount from prior periods, and approved rates are implemented each January.

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

Fuel Costs

Fuel costs are expensed as the fuel is used.

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:

	2006	2005
	(in thousands)	
Generation	**$ 1,347,881**	$ 1,326,766
Transmission	**270,658**	262,168
Distribution	**831,494**	788,711
General	**120,666**	120,339
Plant acquisition adjustment	**3,818**	4,073
Total plant in service	**$ 2,574,517**	$ 2,502,057

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.

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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.7 percent in 2006 and 3.8 percent in 2005 and 2004. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs of an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The liability recognized to retire long-lived assets primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, and a barge unloading dock. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of $9.1 million, primarily related to asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

	2006	2005
	(in thousands)	
Balance beginning of year	**$ 15,298**	$ 5,789
Liabilities incurred	-	9,122
Liabilities settled	-	-
Accretion	**785**	387
Cash flow revisions	**(3,365)**	-
Balance end of year	**$ 12,718**	$ 15,298

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. For the years 2006, 2005, and 2004, the average annual AFUDC rate was 7.48 percent. AFUDC, net of taxes, as a percentage of net income after dividends on preferred and preference stock was 0.61 percent, 1.97 percent, and 3.46 percent, respectively, for 2006, 2005, and 2004.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The cost of such damages is charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $6.5 million in 2006, $9.5 million in 2005, and $18.5 million in 2004. At December 31, 2006, the unrecovered balance in the property damage reserve totaled approximately $45.7 million, of which approximately $28.8 million and $16.9 million is included in Current Assets and Deferred Charges and Other Assets, respectively, in the balance sheets. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information regarding the surcharge mechanism approved by the Florida PSC to replenish these reserves.

Environmental Remediation Cost Recovery

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 received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company's environmental remediation liability balances as of December 31, 2006 and 2005 totaled $57.2 million and $58.2 million, respectively. These estimated costs relate to new regulations and more stringent site closure criteria by the Florida Department of Environmental Protection (FDEP) for impacts to groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery, as expended, through the Company's environmental cost recovery clause; therefore, there was no impact on the Company's net income as a result of these estimates.

Injuries and Damages Reserve

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $2.0 million and $1.7 million at December 31, 2006 and 2005, respectively, and are included in Current Liabilities in the balance sheets. Liabilities in excess of the reserve balance of $1.7 million and $3.0 million at December 31, 2006 and 2005, respectively, are included in Deferred Credits and Other Liabilities in the balance sheets. Corresponding regulatory assets of $1.6 million at both December 31, 2006 and 2005 are included in Current Assets in the balance sheets. At December 31, 2006 and 2005, respectively, $0.1 million and $1.4 million are included in Deferred Charges and Other Assets in the balance sheets.

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, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

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

The compensation cost and tax benefit 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 $1.0 million and $0.6 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $0.4 million.

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

Net Income	As Reported	Options Impact After Tax	Pro Forma
		(in thousands)	
2005	$ 75,209	$ (586)	$ 74,623
2004	68,223	(522)	67,701

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

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

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

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC-approved 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.

Other financial instruments for which the carrying amounts did not equal fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2006	**$ 696,098**	**$ 682,641**
2005	653,629	644,677

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "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 for the Company, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides a defined benefit pension plan for a selected group of management and highly compensated employees. Benefits under this non-qualified plan are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the Florida PSC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $60,000.

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

With the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet previously unrecognized assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $23.5 million with respect to its overfunded defined benefit plan and additional liabilities of $2.5 million and $12.9 million, respectively, related to its underfunded non-qualified pension plan and retiree benefit plans. The incremental effect of applying SFAS No. 158 on individual line items in the balance sheets at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension cost	$ 47	$ 23	$ 70
Other regulatory assets	92	18	110
Other property and investments	16	(1)	15
Total assets	2,300	40	2,340
Accumulated deferred income taxes	(237)	(1)	(238)
Other regulatory liabilities	(23)	(23)	(46)
Employee benefit obligation	(59)	(15)	(74)
Total liabilities	(1,614)	(39)	(1,653)
Accumulated other comprehensive income	6	(1)	5
Total stockholder's equity	(687)	(1)	(688)

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

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

Pension Plans

The accumulated benefit obligation for the pension plans was $242 million in 2006 and $226 million in 2005. Changes during the year in the projected benefit obligations and fair value of plan assets were as follows:

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 248,026**	$ 228,414
Service cost	**6,980**	6,318
Interest cost	**13,359**	12,866
Benefits paid	**(11,034)**	(10,081)
Plan amendments	**385**	1,568
Actuarial (gain) loss	**(11,147)**	8,941
Balance at end of year	**246,569**	248,026
Change in plan assets		
Fair value of plan assets at beginning of year	**280,366**	250,238
Actual return on plan assets	**34,440**	38,478
Employer contributions	**682**	732
Benefits paid	**(11,034)**	(10,081)
Employee transfers	**1,071**	999
Fair value of plan assets at end of year	**305,525**	280,366
Funded status at end of year	**58,956**	32,340
Unrecognized prior service cost	**-**	12,780
Unrecognized net (gain) loss	**-**	(3,845)
Fourth quarter contributions	**147**	200
Prepaid pension asset, net	**$ 59,103**	$ 41,475

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $235.6 million and $10.9 million, respectively. All plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

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

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

	2006	2005
	(in thousands)	
Prepaid pension costs	**$ 69,895**	$ 46,374
Other regulatory assets	**5,091**	-
Current liabilities, other	**(585)**	-
Other regulatory liabilities	**(23,478)**	-
Employee benefit obligations	**(10,207)**	(7,893)
Other property and investments	-	868
Accumulated other comprehensive income	-	2,126

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

	Prior Service Cost	Net (Gain)/ Loss
	(in thousands)	
Balance at December 31, 2006:		
Regulatory assets	$ 401	$ 4,690
Regulatory liabilities	11,153	(34,631)
Total	$ 11,554	$ (29,941)

Estimated amortization in net periodic pension cost in 2007:

	Prior Service Cost	Net (Gain)/ Loss
	(in thousands)	
Regulatory assets	$ 114	$ 360
Regulatory liabilities	1,221	-
Total	$ 1,335	$ 360

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

	2006	2005	2004
		(in thousands)	
Service cost	**$ 6,980**	$ 6,317	$ 5,915
Interest cost	**13,358**	12,866	12,136
Expected return on plan assets	**(20,727)**	(20,816)	(20,689)
Recognized net (gain)/loss	**463**	350	(317)
Net amortization	**1,313**	502	486
Net periodic pension cost (income)	**$ 1,387**	$ (781)	$ (2,469)

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	(in thousands)
2007	$11,080
2008	11,451
2009	11,852
2010	12,369
2011	13,055
2012 to 2016	77,555

Other Postretirement Benefits

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

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 73,280**	$ 69,186
Service cost	**1,424**	1,357
Interest cost	**3,940**	3,892
Benefits paid	**(3,728)**	(3,124)
Actuarial (gain) loss	**(1,124)**	1,969
Retiree drug subsidy	**193**	-
Balance at end of year	**73,985**	73,280
Change in plan assets		
Fair value of plan assets at beginning of year	**16,434**	14,296
Actual return on plan assets	**1,951**	2,114
Employer contributions	**3,583**	3,148
Benefits paid	**(4,328)**	(3,124)
Fair value of plan assets at end of year	**17,640**	16,434
Funded status at end of year	**(56,345)**	(56,846)
Unrecognized transition amount	**-**	2,589
Unrecognized prior service cost	**-**	4,311
Unrecognized net (gain)/loss	**-**	9,026
Fourth quarter contributions	**932**	973
Accrued liability (recognized in the balance sheet)	**$ (55,413)**	$ (39,947)

Other postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	**2006**	2005
Domestic equity	35%	**37%**	38%
International equity	23	**22**	23
Fixed income	18	**19**	21
Real estate	14	**15**	12
Private equity	10	**7**	6
Total	100%	**100%**	100%

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

	2006	2005
	(in thousands)	
Regulatory assets	**$ 12,877**	$ -
Current liabilities, other	**(448)**	-
Employee benefit obligations	**(54,965)**	(39,947)

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

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in thousands)	
Balance at December 31, 2006:			
Regulatory assets	$ 3,965	$ 6,678	$ 2,234
Estimated amortization as net periodic postretirement benefit cost in 2007:			
Regulatory assets	$ 346	$ 97	$ 356

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

	2006	2005	2004
		(in thousands)	
Service cost	**$ 1,424**	$ 1,357	$ 1,275
Interest cost	**3,940**	3,892	4,081
Expected return on plan assets	**(1,264)**	(1,202)	(1,220)
Transition obligation	**356**	356	355
Prior service cost	**346**	346	346
Recognized net (gain)/loss	**155**	33	241
Net postretirement cost	**$ 4,957**	$ 4,782	$ 5,078

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2) related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $0.5 million, $1.1 million, and $1.7 million, respectively, and is expected to have a similar impact on future expenses.

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

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2007	$ 3,373	$ (285)	$ 3,088
2008	3,723	(333)	3,390
2009	4,075	(384)	3,691
2010	4,358	(447)	3,911
2011	4,711	(504)	4,207
2012 to 2016	26,937	(3,627)	23,310

Actuarial Assumptions

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

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	**$ 4,586**	**$ 3,911**
Service and interest costs	**293**	**259**

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $3.0 million, $2.9 million, and $2.7 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after it was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit partially owned by the Company at Plant Scherer. See Note 4 for information on the Company's ownership interest in Plant Scherer Unit 3. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notices of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled.

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

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

At December 31, 2006, the Company's liability for the estimated costs of environmental remediation projects for known sites was $57.2 million. The schedule for completion of the remediation projects will be subject to Florida Department of Environmental Protection (FDEP) approval. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause. Therefore, the Company has recorded $1.7 million in Current Assets and Current Liabilities and $55.5 million in Deferred Charges and Other Assets and Deferred Credits and Other Liabilities representing the future recoverability of these costs.

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

FERC Matters

Market-Based Rate Authority

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

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $3 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

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

Intercompany Interchange Contract

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

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

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

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

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Georgia Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties, and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. The Company's management believes that it has complied with applicable laws and that the plaintiffs' claims are without merit.

In November 2003, the Second Circuit Court in Gadsden County, Florida, ruled in favor of the plaintiffs on their motion for partial summary judgment concerning liability in one such lawsuit brought by landowners regarding the installation and use of fiber optic cable over the Company's rights of way located on the landowners' property. Subsequently, the plaintiffs sought to amend their complaint and asked the court to enter a final declaratory judgment and to enter an order enjoining the Company from allowing expanded general telecommunications use of the fiber optic cables that are the subject of this litigation. In January 2005, the trial court granted in part the plaintiffs' motion to amend their complaint and denied the requested declaratory and injunctive relief. In November 2005, the trial court ruled in favor of the plaintiffs and against the Company on their respective motions for partial summary judgment. In that same order, the trial court also denied the Company's motion to dismiss certain claims. The court's ruling allowed for an immediate appeal to the Florida First District Court of Appeal, which the Company filed in December 2005. On October 26, 2006, the Florida First District Court of Appeal issued an order dismissing the Company's December 2005 appeal on the basis that the trial court's order was a non-final order and therefore not subject to review on appeal at this time. The case is once again pending in the trial court for further proceedings. The final outcome of this matter cannot now be determined. In the event of an adverse verdict in this case, the Company could appeal the issues of both liability and damages or other relief granted.

In addition, in late 2001, certain subsidiaries of Southern Company, including the Company, Alabama Power, Georgia Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

Georgia Power and the Company are involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial increases in the ad valorem tax valuation of the Company's 6.25 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003 through 2006. Georgia Power and the Company are aggressively pursuing administrative appeals in Monroe County and have filed notices of arbitration for all four years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, Georgia Power filed suit, on its own behalf, against the Monroe Board in the Superior Court of Monroe County. The suit could impact all co-owners. Georgia Power contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from Georgia Power. In December 2005, the Court granted Monroe County's motion for summary judgment. Georgia Power has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If Georgia Power is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2006 of up to $4.4 million, plus penalties and interest. In accordance with the Company's unit power sales contract for Plant Scherer, such property taxes would be recoverable from the customer. The final outcome of this matter cannot now be determined.

Retail Regulatory Matters

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA. During 2006, 2005, and 2004, the Company recorded environmental cost recovery clause revenues of $40.9 million, $26.3 million, and $14.7 million, respectively. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2006, the over recovered balance was $6.8 million primarily due to operations and maintenance expenses being less than anticipated.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida PSC issued an order (2005 Order) that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through the two-year surcharge that began in April 2005.

In July 2006, the Florida PSC issued an order (2006 Order) approving another stipulation and settlement between the Company and several consumer groups that resolved all matters relating to the Company's request for recovery of incurred costs for storm-recovery activities related to the 2005 storms and the replenishment of the Company's property damage reserve. The 2006 Order provides for an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009.

According to the 2006 Order, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by the Company through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve.

The annual accrual to the reserve of $3.5 million and the Company's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. The Company made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of the 2005 Order regarding Hurricane Ivan costs that established the existing surcharge, the Company agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the 2006 Order do not alter or affect that portion of the prior agreement.

According to the 2006 Order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism.

See Note 1 under "Property Damage Reserve" for additional information.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 megawatts (MW). Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's pro rata share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income.

At December 31, 2006, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$ 191,319[(a)]	$ 253,370
Accumulated depreciation	90,889	138,472
Construction work in progress	2,430	699
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $3.8 million.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined State of Mississippi and State of Georgia income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

At December 31, 2006, the tax-related regulatory assets to be recovered from customers were $17.1 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 2006, the tax-related regulatory liabilities to be credited to customers were $17.9 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2006	2005	2004
		(in thousands)	
Federal –			
Current	**$ 40,472**	$ 11,330	$ (4,255)
Deferred	**(470)**	26,693	39,373
	40,002	38,023	35,118
State –			
Current	**3,651**	490	(2,305)
Deferred	**1,640**	6,468	6,882
	5,291	6,958	4,577
Total	**$ 45,293**	$ 44,981	$ 39,695

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

	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$ 245,147**	$ 245,906
Fuel recovery clause	**31,380**	12,812
Pension benefits and employee benefit obligations	**23,888**	14,817
Property reserve	**17,612**	29,393
Regulatory assets associated with employee benefit obligations	**10,940**	-
Regulatory assets associated with asset retirement obligations	**5,151**	6,195
Other	**6,492**	6,352
Total	**340,610**	315,475
Deferred tax assets:		
Federal effect of state deferred taxes	**$ 13,713**	$ 13,591
Post retirement benefits	**15,082**	13,430
Pension benefits	**13,310**	2,054
Other comprehensive loss	**2,887**	1,765
Regulatory liabilities associated with employee benefit obligations	**9,057**	-
Asset retirement obligations	**5,151**	6,195
Other	**13,777**	13,082
Total	**72,977**	50,117
Net deferred tax liabilities	**267,633**	265,358
Less current portion, net	**(29,771)**	(8,868)
Accumulated deferred income taxes in the balance sheets	**$ 237,862**	$ 256,490

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 $1.8 million in 2006, $1.9 million in 2005, and $2.0 million in 2004. At December 31, 2006, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.8**	3.7	2.8
Non-deductible book depreciation	**0.5**	0.7	0.6
Difference in prior years' deferred and current tax rate	**(0.8)**	(0.8)	(1.1)
Other, net	**(1.1)**	(1.4)	(0.6)
Effective income tax rate	**36.4%**	37.2%	36.7%

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 $41.2 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trusts' payment obligations with respect to these securities. At December 31, 2006, $41.2 million of these securities were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2006. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding preference stock is subject to redemption at the option of the Company on or after November 15, 2010.

On January 19, 2007, the Company issued to Southern Company 800,000 shares of the Company's common stock, without par value, and realized proceeds of $80 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds totaling $157.6 million.

Assets Subject to Lien

In January 2007, the Company's first mortgage bond indenture was discharged. As a result, there are no longer any first mortgage liens on the Company's property and the Company no longer has to comply with the covenants and restrictions of the first mortgage bond indenture. The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control bonds with an outstanding principal amount of $41 million.

There are no agreements or other arrangements among the affiliated companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At the beginning of 2007, the Company had $120 million of lines of credit with banks subject to renewal each year, all of which remained unused. Of the $120 million, $116 million provides liquidity support for the Company's commercial paper program and $4 million of daily variable rate pollution control bonds. In connection with these credit lines, the Company has agreed to pay commitment fees.

Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. At December 31, 2006, the Company was in compliance with these covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants. In the event of a material adverse change, as defined in the Company's credit agreements, the Company would be prohibited from borrowing against unused credit arrangements totaling $10 million.

The Company borrows primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks and through an extendible commercial note program. At December 31, 2006, the Company had $80.4 million in commercial paper and $40 million in bank notes outstanding. At December 31, 2005, the Company had $14.5 million in commercial paper and $75 million in bank notes outstanding. During 2006, the peak amount outstanding for short term debt was $181.6 million and the average amount outstanding was $113.8 million. The average annual interest rate on commercial paper was 5.36 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs with the approval of the Florida PSC. The Company enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, and 2004.

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

	Amounts (in thousands)
Regulatory assets, net	$(7,186)
Net income	-
Total fair value	$(7,186)

The fair value gains or losses for cash flow hedges that are recoverable through the regulatory fuel clauses are recorded as regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2009.

The Company also may enter into derivatives to hedge exposure to interest rate changes. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings.

In 2006, the Company terminated interest rate derivatives, at the same time the related debt was issued, with a notional value of $80 million at a cost of $5.4 million. The hedge cost will be amortized over a 10-year period. The Company had no interest rate derivatives at December 31, 2006. For the years 2006, 2005, and 2004, approximately $0.4 million, $0.3 million, and $0.3 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2007, pre-tax losses of approximately $0.9 million are expected to be reclassified from other comprehensive income to interest expense. The Company has losses that are being amortized through 2016.

7. COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $278 million in 2007, $458 million in 2008, and $395 million in 2009. The construction program is 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; acquisition of additional generating assets; revised load growth estimates; changes in environmental regulations; changes in FERC rules and regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the ongoing construction program.

Included in the amounts above are $171 million in 2007, $378 million in 2008, and $300 million in 2009 for environmental expenditures. The Company does not have any new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for combined cycle generating facility. The LTSA provides 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 the contract.

In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under this agreement for facilities owned are currently estimated at $74.9 million over the remaining life of the agreement, which is currently estimated to be up to 9 years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in Current Assets and Deferred Charges and Other Assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power and Fuel Commitments

The Company has entered into long-term commitments for the purchase of electricity.

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006.

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

Year	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2007	$ -	$ 117,726	$ 281,401
2008	-	90,371	240,222
2009	23,832	65,975	69,998
2010	26,811	43,194	70,764
2011	26,861	20,081	-
2012 and thereafter	57,915	189,106	-
Total commitments	$ 135,419	$ 526,453	$ 662,385

*Included above is $76 million in obligations with affiliated companies.

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

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

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $4.9 million, $3.0 million, and $2.0 million, for 2006, 2005, and 2004, respectively. Included in these lease expenses are railcar lease costs which are charged to fuel inventory and are allocated to fuel expense as the fuel is used. These expenses are then recovered through the Company's fuel cost recovery clause. The Company's share of the lease costs charged to fuel inventories was $4.6 million in 2006, $3.0 million in 2005, and $1.9 million in 2004. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

At December 31, 2006, estimated minimum rental commitments for noncancelable operating leases were as follows:

Year	Rail Cars	Other	Total
		(in thousands)	
2007	$ 4,043	$ 337	$ 4,380
2008	3,072	339	3,411
2009	2,039	185	2,224
2010	2,006	59	2,065
2011	596	-	596
2012 and thereafter	3,574	-	3,574
Total minimum payments	$ 15,330	$ 920	$ 16,250

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's share of these leases was charged to fuel handling expense in the amount of $0.3 million in 2006. The Company's annual lease payments for 2007 to 2010 will average approximately $0.2 million.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2006, there were 283 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options, that were used under SFAS No. 123.

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

	Shares Subject to Option	Weighted-Average Exercise Price
Outstanding at Dec. 31, 2005	1,099,549	$ 27.07
Granted	242,373	33.81
Exercised	(142,941)	24.20
Cancelled	(460)	32.66
Outstanding at Dec. 31, 2006	1,198,521	$ 28.77
Exercisable at Dec. 31, 2006	735,425	$ 26.27

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

As of December 31, 2006, the weighted average remaining contractual term for options outstanding and options exercisable is 6.6 years and 5.5 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $9.7 million and $7.8 million, respectively.

As of December 31, 2006, there was $0.5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $1.6 million, $4.4 million, and $4.6 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $0.6 million, $1.7 million, and $1.8 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2006 and 2005 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in thousands)	
March 2006	**$ 263,042**	**$ 31,079**	**$12,402**
June 2006	**292,722**	**47,062**	**22,038**
September 2006	**373,030**	**66,511**	**34,577**
December 2006	**275,120**	**22,020**	**6,972**
March 2005	$ 224,597	$ 31,229	$14,646
June 2005	251,297	44,153	21,458
September 2005	344,080	68,571	37,197
December 2005	263,648	14,324	1,908

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

SELECTED FINANCIAL AND OPERATING DATA 2002-2006
Gulf Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	**$ 1,203,914**	$ 1,083,622	$ 960,131	$ 877,697	$ 820,467
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$ 75,989**	$ 75,209	$ 68,223	$ 69,010	$ 67,036
Cash Dividends on Common Stock (in thousands)	**$ 70,300**	$ 68,400	$ 70,000	$ 70,200	$ 65,500
Return on Average Common Equity (percent)	**12.29**	12.59	11.83	12.42	12.72
Total Assets (in thousands)	**$ 2,340,489**	$ 2,175,797	$ 2,111,877	$ 1,839,053	$ 1,816,889
Gross Property Additions (in thousands)	**$ 147,086**	$ 142,583	$ 161,205	$ 99,284	$ 106,624
Capitalization (in thousands) :					
Common stock equity	**$ 634,023**	$ 602,344	$ 592,172	$ 561,358	$ 549,505
Preferred and preference stock	**53,887**	53,891	4,098	4,236	4,236
Mandatorily redeemable preferred securities	**-**	-	-	70,000	115,000
Long-term debt payable to affiliated trusts	**41,238**	72,166	72,166	-	-
Long-term debt	**654,860**	544,388	550,989	515,827	452,040
Total (excluding amounts due within one year)	**$ 1,384,008**	$ 1,272,789	$ 1,219,425	$ 1,151,421	$ 1,120,781
Capitalization Ratios (percent):					
Common stock equity	**45.8**	47.3	48.6	48.8	49.0
Preferred and preference stock	**3.9**	4.2	0.3	0.4	0.4
Mandatorily redeemable preferred securities	**-**	-	-	6.1	10.3
Long-term debt payable to affiliated trusts	**3.0**	5.7	5.9	-	-
Long-term debt	**47.3**	42.8	45.2	44.7	40.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody’s	**-**	A1	A1	A1	A1
Standard and Poor’s	**-**	A+	A+	A+	A+
Fitch	**-**	A+	A+	A+	A+
Preferred Stock/Preference Stock -					
Moody’s	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor’s	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A-**	A-	A-	A-	A-
Unsecured Long-Term Debt -					
Moody’s	**A2**	A2	A2	A2	A2
Standard and Poor’s	**A**	A	A	A	A
Fitch	**A**	A	A	A	A
Customers (year-end):					
Residential	**364,647**	354,466	343,151	341,935	333,757
Commercial	**53,466**	53,398	51,865	51,169	49,411
Industrial	**295**	298	285	285	281
Other	**484**	479	473	473	474
Total	**418,892**	408,641	395,774	393,862	383,923
Employees (year-end)	**1,321**	1,335	1,336	1,337	1,339

SELECTED FINANCIAL AND OPERATING DATA 2002-2006 (continued)
Gulf Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands) :					
Residential	**$ 510,995**	$ 465,346	$ 401,382	$ 381,464	$ 365,693
Commercial	**305,049**	273,114	232,928	218,928	207,960
Industrial	**132,339**	123,044	99,420	95,702	89,385
Other	**3,655**	3,355	3,140	3,080	2,798
Total retail	**952,038**	864,859	736,870	699,174	665,836
Sales for resale - non-affiliates	**87,142**	84,346	73,537	76,767	77,171
Sales for resale - affiliates	**118,097**	91,352	110,264	63,268	40,391
Total revenues from sales of electricity	**1,157,277**	1,040,557	920,671	839,209	783,398
Other revenues	**46,637**	43,065	39,460	38,488	37,069
Total	**$ 1,203,914**	$ 1,083,622	$ 960,131	$ 877,697	$ 820,467
Kilowatt-Hour Sales (in thousands):					
Residential	**5,425,491**	5,319,630	5,215,332	5,101,099	5,143,802
Commercial	**3,843,064**	3,735,776	3,695,471	3,614,255	3,552,931
Industrial	**2,136,439**	2,160,760	2,113,027	2,146,956	2,053,668
Other	**23,886**	22,730	22,579	22,479	21,496
Total retail	**11,428,880**	11,238,896	11,046,409	10,884,789	10,771,897
Sales for resale - non-affiliates	**2,079,165**	2,295,850	2,256,942	2,504,211	2,156,741
Sales for resale - affiliates	**2,937,735**	1,976,368	3,124,788	2,438,874	1,720,240
Total	**16,445,780**	15,511,114	16,428,139	15,827,874	14,648,878
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**9.42**	8.75	7.70	7.48	7.11
Commercial	**7.94**	7.31	6.30	6.06	5.85
Industrial	**6.19**	5.69	4.71	4.46	4.35
Total retail	**8.33**	7.70	6.67	6.42	6.18
Sales for resale	**4.09**	4.11	3.42	2.83	3.03
Total sales	**7.04**	6.71	5.60	5.30	5.35
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,032**	15,181	15,096	15,064	15,510
Residential Average Annual Revenue Per Customer	**$ 1,416**	$ 1,328	$ 1,162	$ 1,126	$ 1,100
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,659**	2,712	2,712	2,786	2,809
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,195**	2,124	2,061	2,494	2,182
Summer	**2,479**	2,433	2,421	2,269	2,454
Annual Load Factor (percent)	**57.9**	57.7	57.1	54.6	55.3
Plant Availability Fossil-Steam (percent)	**91.3**	89.7	92.4	90.7	90.6
Source of Energy Supply (percent) :					
Coal	**82.5**	79.7	77.9	78.7	69.8
Gas	**12.4**	13.1	14.4	11.9	15.5
Purchased power -					
From non-affiliates	**1.9**	2.8	4.5	3.2	4.6
From affiliates	**3.2**	4.4	3.2	6.2	10.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Gulf Power Company 2006 Annual Report

DIRECTORS

Susan N. Story
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2003

C. LeDon Anchors
Attorney at Law and President
Anchors Smith Grimsley
A Professional Limited Company
Fort Walton Beach, Florida. Elected 2001

William C. Cramer, Jr.
President and Owner
Tommy Thomas Chevrolet, Inc.
Panama City, Florida. Elected 2002

Fred C. Donovan, Sr.
Chairman and Chief Executive Officer
Baskerville-Donovan, Inc.
Pensacola, Florida. Elected 1991

William A. Pullum
Broker/President
Bill Pullum Realty, Inc.
Navarre, Florida. Elected 2001

Winston E. Scott
Vice President, Deputy General Manager
Engineering and Science Contract Group
Jacobs Engineering
Houston, Texas. Elected 2003

OFFICERS

Susan N. Story
President and Chief Executive Officer
Age 46; 24 Years of Service

Francis M. Fisher, Jr. (1)
Vice President - Customer Operations
Age 58; 35 Years of Service

P. Bernard Jacob (2)
Vice President – Customer Operations
Age 52; 24 Years of Service

Ronnie R. Labrato
Vice President and Chief Financial Officer
Age 53; 27 Years of Service

Penny M. Manuel
Vice President – Senior Production Officer
Age 44; 24 Years of Service

Bentina C. Terry (3)
Vice President – External Affairs and
Corporate Services
Age 37; 6 Years of Service

Connie J. Erickson
Comptroller
Age 41; 4 Years of Service

Susan D. Ritenour
Secretary and Treasurer
Age 47; 25 Years of Service

Linda G. Malone (4)
Assistant Secretary and Assistant Treasurer
Age 57; 36 Years of Service

Terry A. Davis
Assistant Secretary and Assistant Treasurer
Age 49; 20 Years of Service

Robert A. Bell
Vice President
Age 55; 33 Years of Service

E. Wayne Boston
Assistant Secretary and Assistant Treasurer
Age 62; 36 Years of Service

(1) Retiring effective May 1, 2007.
(2) Title change effective March 24, 2007; Previously Vice President – External Affairs and Corporate Services.
(3) Elected effective March 24, 2007.
(4) Retired effective June 1, 2006.

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Florida. The Company sells electricity to approximately 419,000 customers within its service area of approximately 7,400 square miles in the Florida panhandle. In 2006, retail energy sales accounted for 69 percent of the Company's total sales of 16.4 billion kilowatt-hours.

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

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

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and
Trust Preferred Securities
The Bank of New York
Global Trust Administration
101 Barclay Street, 8 West
New York, New York 10286

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

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary at the mailing address below:

Corporate Office
Principal Address & Deliveries:
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Pensacola, FL 32520
(850) 444-6111

Mailing Address:
Gulf Power Company
One Energy Place
Pensacola, FL 32520

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Deloitte & Touche LLP
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191 Peachtree Street, N.E.
Atlanta, GA 30303-1924

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
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