GEORGIA POWER COMPANY

2008 Annual Report

GEORGIA POWER
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2008 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

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

Michael D. Garrett
President and Chief Executive Officer

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

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, 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, 2008. 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 27 to 66) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. In December 2007, the Company completed a major retail rate proceeding (2007 Retail Rate Plan) that enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution networks, continued generation, and other investments as well as the recovery of increased operating costs. The 2007 Retail Rate Plan includes a tariff specifically for the recovery of costs related to environmental controls mandated by state and federal regulations. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a general rate case by July 1, 2010, which will determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued. The Company also received regulatory orders to increase its fuel cost recovery rate effective July 1, 2006, March 1, 2007, and June 1, 2008. The Company expects to file its next fuel cost recovery case on March 13, 2009.

Key Performance Indicators

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

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2008 fossil/hydro Peak Season EFOR of 0.84% was better than the target. The nuclear generating fleet also uses Peak Season EFOR as an indicator of availability and efficient generation fleet operations during the peak season. The 2008 nuclear Peak Season EFOR of 1.64% was also better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The 2008 performance was better than the target for these reliability measures. Net income after dividends on preferred and preference stock is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2008 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile in customer surveys
Peak Season EFOR – fossil/hydro	2.75% or less	0.84%
Peak Season EFOR – nuclear	2.00% or less	1.64%
Net Income	$900 million	$903 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2008 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 2008 net income after dividends on preferred and preference stock totaled $903 million representing a $66.8 million, or 8.0%, increase over 2007. The increase was primarily related to increased contributions from market-response rates for large commercial and industrial customers, higher retail base revenues resulting from the retail rate increase effective January 1, 2008, and increased allowance for equity funds used during construction. These increases were partially offset by increased depreciation and amortization resulting from more plant in service and changes to depreciation rates. The Company's 2007 earnings totaled $836 million representing a $48.9 million, or 6.2%, increase over 2006. Operating income increased slightly in 2007 primarily due to increased operating revenues from transmission and outdoor lighting and decreased property taxes, partially offset by higher non-fuel operating expenses. Net income increased primarily due to higher allowance for equity funds used during construction and lower income tax expenses resulting from the Company's donation of Tallulah Gorge to the State of Georgia, partially offset by higher financing costs. The Company's 2006 earnings totaled $787 million representing a $42.9 million, or 5.8%, increase over 2005. Operating income increased in 2006 due to higher base retail revenues and wholesale non-fuel revenues, partially offset by an increase in non-fuel operating expenses.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	**Increase (Decrease) from Prior Year**		
	2008	**2008**	2007	2006
		(in millions)		
Operating revenues	**$ 8,412**	**$ 840**	$ 326	$ 170
Fuel	**2,813**	**172**	408	296
Purchased power	**1,405**	**355**	(95)	(171)
Other operations and maintenance	**1,581**	**19**	1	(11)
Depreciation and amortization	**637**	**126**	13	(28)
Taxes other than income taxes	**316**	**25**	(8)	23
Total operating expenses	**6,752**	**697**	319	109
Operating income	**1,660**	**143**	7	61
Total other income and (expense)	**(252)**	**5**	18	(22)
Income taxes	**488**	**70**	(25)	(5)
Net income	**920**	**78**	50	44
Dividends on preferred and preference stock	**17**	**11**	1	1
Net income after dividends on preferred and preference stock	**$ 903**	**$ 67**	$ 49	$ 43

Operating Revenues

Operating revenues in 2008, 2007, and 2006, and the percent of change from the prior year were as follows:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	**$ 6,498.0**	$ 6,205.6	$ 6,064.4
Estimated change in –			
Rates and pricing	**396.9**	(66.2)	(76.8)
Sales growth	**(20.9)**	46.5	76.6
Weather	**(37.7)**	17.7	7.5
Fuel cost recovery	**450.1**	294.4	133.9
Retail – current year	**7,286.4**	6,498.0	6,205.6
Wholesale revenues –			
Non-affiliates	**568.8**	537.9	551.7
Affiliates	**286.2**	277.9	252.6
Total wholesale revenues	**855.0**	815.8	804.3
Other operating revenues	**270.2**	257.9	235.7
Total operating revenues	**$ 8,411.6**	$ 7,571.7	$ 7,245.6
Percent change	**11.1%**	4.5%	2.4%

Retail base revenues of $4.1 billion in 2008 increased by $338.3 million, or 9.0%, from 2007 primarily due to an increase in revenues from market-response rates to large commercial and industrial customers, the retail rate increase effective January 1, 2008, and a 0.7% increase in retail customers. The increase was partially offset by a weak economy in the Southeast and more favorable weather impacts in 2007 than in 2008. Retail base revenues were $3.8 billion in 2007. There was not a material change in total retail base revenues compared to 2006, although industrial base revenues decreased $56.5 million, or 8.5%, primarily due to lower sales and a lower contribution from market-response rates for large commercial and industrial customers. This decrease was partially offset by a $31.8 million, or 2.1%, increase in residential base revenues as well as a $22.6 million, or 1.5%, increase in commercial base revenues primarily due to higher sales from favorable weather and customer growth of 1.2%. Retail base revenues of $3.8 billion in 2006 increased by $7 million, or 0.2%, from 2005 primarily due to customer growth of 1.9% and more favorable weather, partially offset by lower contributions from market-response rates to large commercial and industrial customers. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

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

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

	2008	2007	2006
		(in millions)	
Unit power sales –			
Capacity	**$ 40**	$ 33	$ 33
Energy	**44**	33	38
Total	**84**	66	71
Other power sales –			
Capacity and other	**129**	158	165
Energy	**356**	314	316
Total	**485**	472	481
Total non-affiliated	**$569**	$538	$552

Wholesale revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation.

Revenues from unit power sales increased $18.2 million, or 27.4%, in 2008 driven by higher fuel rates and an 8.2% increase in the kilowatt-hour (KWH) energy sales primarily related to sales by the Company's generating units when other Southern Company system units were unavailable. Revenues from unit power sales remained relatively constant in 2007 and 2006. Revenues from other non-affiliated sales increased $12.7 million, or 2.7%, in 2008, decreased $9.6 million, or 2.0%, in 2007, and increased $21.0 million, or 4.6%, in 2006. The increase in 2008 was primarily driven by the fuel component within non-affiliate wholesale prices which has increased with the effects of higher fuel and purchased power costs. This increase was partially offset by a 9.8% decrease in KWH energy sales and decreased contributions from the emissions allowance component of market-based wholesale rates. The decrease in 2007 was primarily due to a decrease in revenues from large territorial contracts resulting from lower emissions allowance prices. The increase in 2006 was due to a 0.6% increase in the demand for KWH energy sales due to a new contract with an electrical membership corporation that went into effect in April 2006.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2008, KWH energy sales to affiliated companies decreased 28.8% while revenues from sales to affiliates increased 3.0%. In 2007, KWH energy sales to affiliates decreased 5.0% while revenues from sales to affiliates increased 10.0%. The revenue increases in 2008 and 2007 were primarily due to the increased cost of fuel and other marginal generation components of the rates. In 2006, KWH energy sales to affiliates increased 8.5% due to higher demand. However, revenues from these sales decreased by 8.3% in 2006 due to reduced cost per KWH delivered. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $12.3 million, or 4.8%, in 2008 primarily due to a $6.7 million increase in revenues from outdoor lighting resulting from a 15.8% increase in lighting customers and a $7.6 million increase in customer fees resulting from higher rates that went into effect in 2008, partially offset by a $2.2 million decrease in equipment rentals revenue. Other operating revenues increased $22.2 million, or 9.4%, in 2007 primarily due to an $11.6 million increase in transmission revenues due to the increased usage of the Company's transmission system by non-affiliated companies, a $7.9 million increase in revenues from outdoor lighting activities due to a 10% increase in the number of lighting customers, and a $4.0 million increase from customer fees. Other operating revenues increased $24.6 million, or 11.6%, in 2006 primarily due to increased revenues of $14.1 million related to work performed for the other owners of the integrated transmission system in the State of Georgia, higher customer fees of $4.6 million, and higher outdoor lighting revenues of $6.1 million.

Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2008 and the percent change by year were as follows:

	KWH	Percent Change		
	2008	**2008**	2007	2006
	(in billions)			
Residential	**26.4**	**(1.6)%**	2.4%	2.7%
Commercial	**33.0**	**0.0**	2.9	2.5
Industrial	**24.2**	**(5.2)**	(0.3)	(1.0)
Other	**0.7**	**(3.8)**	5.6	(10.5)
Total retail	**84.3**	**(2.1)**	1.8	1.4
Wholesale				
Non-affiliates	**9.8**	**(7.8)**	(1.0)	0.9
Affiliates	**3.7**	**(28.8)**	(5.0)	8.5
Total wholesale	**13.5**	**(14.7)**	(2.3)	3.4
Total energy sales	**97.8**	**(4.0)%**	1.1%	1.7%

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales decreased 1.6% in 2008 compared to 2007 primarily due to less favorable weather, partially offset by a 0.7% increase in residential customers. Commercial KWH sales remained flat in 2008 compared to 2007 despite a 0.2% increase in commercial customers. Industrial KWH sales decreased 5.2% in 2008 over 2007 primarily due to reduced demand and closures within the textile and primary and fabricated metal industries, a result of the slowing economy that worsened during the fourth quarter 2008.

Residential KWH sales increased 2.4% in 2007 over 2006 due to favorable weather and a 1.3% increase in residential customers. Commercial KWH sales increased 2.9% in 2007 over 2006 primarily due to favorable weather and a 0.3% increase in commercial customers. Industrial KWH sales decreased 0.3% primarily due to reduced demand and closures within the textile industry; however, this was partially offset by a 2.9% increase in the number of industrial customers.

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

Fuel and Purchased Power Expenses

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

	2008	2007	2006
Total generation *(billions of KWHs)*	**80.8**	87.0	83.7
Total purchased power *(billions of KWHs)*	**21.3**	18.9	21.9
Sources of generation *(percent)* -			
Coal	**74**	75	75
Nuclear	**19**	18	18
Gas	**6**	7	6
Hydro	**1**	-	1
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**3.44**	2.87	2.58
Nuclear	**0.51**	0.51	0.47
Gas	**6.90**	6.28	5.76
Average cost of fuel, generated *(cents per net KWH)*	**3.11**	2.68	2.39
Average cost of purchased power *(cents per net KWH)*	**8.10**	7.27	6.38

Fuel and purchased power expenses were $4.2 billion in 2008, an increase of $526.6 million, or 14.3%, above prior year costs. Substantially all of this increase was due to the higher average cost of fuel and purchased power.

Fuel and purchased power expenses were $3.7 billion in 2007, an increase of $312.9 million, or 9.3%, above prior year costs. This increase was driven by a $414.5 million increase in total energy costs due to the higher average cost of fuel and purchased power, partially offset by a $101.6 million reduction due to fewer KWHs purchased.

Fuel and purchased power expenses were $3.4 billion in 2006, an increase of $124.4 million, or 3.8%, above prior year costs. This increase was driven by a $146.1 million increase related to higher KWHs generated and purchased, partially offset by a $21.7 million decrease in the average cost of fuel and purchased power.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy. During 2008, uranium prices continued to moderate from the highs set during 2007. While worldwide uranium production levels appear to have increased slightly since 2007, secondary supplies and inventories were still required to meet worldwide reactor demand.

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 for additional information.

Other Operations and Maintenance Expenses

In 2008, other operations and maintenance expenses increased \$19.2 million, or 1.2%, compared to 2007. The increase was primarily the result of a \$14.7 million increase in the accrual for property damage approved under the 2007 Retail Rate Plan, a \$14.6 million increase in scheduled outages and maintenance for fossil generating plants, and a \$22.0 million increase related to meter reading, records and collections, and uncollectible account expenses. These increases were partially offset by decreases of \$24.7 million related to the timing of transmission and distribution operations and maintenance and \$7.4 million related to medical, pension, and other employee benefits.

In 2007, the change in other operations and maintenance expenses was immaterial compared to 2006.

In 2006, other operations and maintenance expenses decreased \$11.0 million, or 0.7%, from the prior year. Maintenance for generating plants decreased \$20.0 million in 2006 as a result of fewer scheduled outages than 2005, offset by an increase of \$18.2 million for transmission and distribution expenses related to load dispatching and overhead line maintenance. Also contributing to the decrease were lower employee benefit expenses related to medical benefits and lower workers compensation expense of \$23.2 million, partially offset by lower pension income of \$13.7 million.

Depreciation and Amortization

Depreciation and amortization increased \$125.8 million, or 24.6%, in 2008 compared to the prior year primarily due to an increase in plant in service related to completed transmission, distribution, and environmental projects, changes in depreciation rates effective January 1, 2008 approved under the 2007 Retail Rate Plan, and the expiration of amortization related to a regulatory liability for purchased power costs under the terms of the retail rate plan for the three years ended December 31, 2007 (2004 Retail Rate Plan).

Depreciation and amortization increased \$12.4 million, or 2.5%, in 2007 compared to the prior year primarily due to a 3.4% increase in plant in service from the prior year. This increase was partially offset by a decrease in amortization of the regulatory liability for purchased power costs as described above.

Depreciation and amortization decreased \$27.9 million, or 5.3%, in 2006 compared to the prior year due to the scheduled decrease in amortization related to the regulatory liability for purchased power costs as described above. This decrease was partially offset by a \$15.9 million, or 3.2%, increase in depreciation in 2006 over 2005 due to an increase in plant in service. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Taxes Other Than Income Taxes

In 2008, taxes other than income taxes increased \$25.1 million, or 8.6%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2008. Taxes other than income taxes decreased \$7.7 million, or 2.6%, in 2007 primarily due to the resolution of a dispute regarding property taxes in Monroe County, Georgia. Taxes other than income taxes increased \$22.8 million, or 8.3%, in 2006 primarily due to higher property taxes of \$13.3 million as a result of an increase in property values and higher municipal gross receipts taxes of \$9.1 million as a result of increased retail operating revenues.

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) increased \$27.1 million, or 39.8%, in 2008 primarily due to the increase in construction work in progress balances related to ongoing environmental and transmission projects as well as three combined cycle generating units at Plant McDonough. AFUDC increased \$36.7 million, or 116.3%, in 2007 primarily due to the increase in the Company's construction work in progress balance related to ongoing transmission, distribution, and environmental projects. AFUDC remained relatively constant in 2006 when compared to 2005.

Interest Expense, Net of Amounts Capitalized

The increase in interest expense in 2008 was immaterial. Interest expense increased \$25.5 million, or 8.0%, in 2007 primarily due to a 13.9% increase in long-term debt levels due to the issuance of additional senior notes and pollution control revenue bonds. Interest expense increased \$22.5 million, or 7.6%, in 2006 primarily due to generally higher interest rates on variable rate debt and commercial paper, the issuance of additional senior notes, and higher average balances of short-term debt.

Other Income (Expense), Net

Other income (expense), net decreased $24.0 million, or 163.0%, in 2008 primarily due to a $12.9 million change in classification of revenues related to a residential pricing program to base retail revenues in 2008 as ordered by the Georgia PSC under the 2007 Retail Rate Plan, as well as decreased revenues of $7.3 million and $2.6 million related to non-operating rental income and customer contracting, respectively. Other income (expense), net increased $5.8 million, or 66.5%, in 2007 primarily due to $4.0 million from land and timber sales. Other income (expense), net increased $1.9 million, or 26.7%, in 2006 primarily due to reduced expenses of $2.9 million and $5.0 million related to the employee stock ownership plan and charitable donations, respectively, and increased revenues of $3.6 million, $5.4 million, and $3.4 million related to a residential pricing program, customer contracting, and customer facilities charges, respectively. These increases were partially offset by net financial gains on gas hedges of $18.6 million in 2005.

Income Taxes

Income taxes increased $70.0 million, or 16.8%, in 2008 primarily due to increased pre-tax net income and the 2007 Tallulah Gorge donation. These increases were partially offset by an increase in AFUDC, which is non-taxable, as well as additional state tax credits and an increase in the federal production activities deduction. Income taxes decreased $24.8 million, or 5.6%, in 2007 primarily due to state and federal deductions for the Company's donation of 2,200 acres in the Tallulah Gorge area to the State of Georgia and higher federal manufacturing deductions. In 2006, income taxes decreased $5.1 million, or 1.1%, primarily due to the recognition of state tax credits. See Note 5 to the financial statements for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation or market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, 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 or the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt, preferred securities, preferred stock, and preference stock. 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 within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for electricity relating to wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and revenues are reviewed and adjusted periodically with certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" and "FERC Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales during the current economic downturn, 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 or decline in the service area. Recent recessionary conditions have negatively impacted sales growth. The timing and extent of the economic recovery will impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. Under the 2007 Retail Rate Plan, an environmental compliance cost recovery (ECCR) tariff was implemented on January 1, 2008 to allow for the recovery of most of the costs related to environmental controls mandated by state and federal regulation scheduled for completion between 2008 and 2010. The Company has also requested that the Georgia PSC certify the construction of environmental controls for Plants Branch and Hammond. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities including the Company's Plants Bowen and Scherer. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against the Company has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to 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. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 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 all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve 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 $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. 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. The 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, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter 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; the Endangered Species Act; and related federal and state regulations. 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 2008, the Company had invested approximately $3.1 billion in capital projects to comply with these requirements, with annual totals of $689 million, $856 million, and $352 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to ensure compliance with existing and new statutes and regulations will be an additional $472 million, $334 million, and $399 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, 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 2008, the Company had spent approximately $2.8 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. Areas within the Company's service area that were designated as nonattainment under the eight-hour ozone standard included Macon and a 20-county area within metropolitan Atlanta. The Macon area has since been redesignated as an attainment area by the EPA, and a maintenance plan to address future exceedances of the standard has been approved. A state plan for bringing the Atlanta area into attainment with this standard was due to the EPA in 2007; however, in December 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA rules designed to provide states with the guidance necessary to develop such plans. State plans could require additional reductions in NOx emissions from power plants. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which will likely result in designation of new nonattainment areas within the Company's service territory. The EPA is expected to publish those designations in 2010 and require state implementation plans for any nonattainment areas by 2013.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the Company's service area. State plans for addressing the nonattainment designations for this standard were due by April 5, 2008 but have not been finalized. These state plans could require further reductions in SO_2 and NO_x emissions from power plants.

The EPA issued the final Clean Air Interstate Rule (CAIR) 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 Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The State of Georgia has completed plans to implement CAIR and has approved a "multi-pollutant rule" that requires plant-specific emission controls on all but the smallest generating units in Georgia to be installed according to a schedule set forth in the rule. The rule is designed to ensure reductions in emissions of SO_2, NO_x, and mercury in Georgia. Emission reductions are thus being accomplished by the installation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. The full impact of the court's remand and the outcome of the EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. At the request of the State of Georgia, additional analyses were performed for certain units in Georgia to demonstrate that no additional SO_2 controls were required to demonstrate reasonable progress. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone nonattainment designations, the fine particulate matter nonattainment designations, and the Clean Air Visibility Rule on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the Clean Air Mercury Rule. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NO_x controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the Clean Air Mercury Rule.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. 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 be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

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

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

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of any similar state legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include the proposed construction of two additional nuclear generating units at Plant Vogtle and additional renewable energy investments, including the proposed conversion of Plant Mitchell from coal-fired to biomass generation. The Company is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies for Georgia.

FERC Matters

Market-Based Rate Authority

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

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $5.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of the FERC's methodology for determining the amount of refunds. The requested rehearings were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

PSC Matters

Rate Plans

In December 2007, the Georgia PSC approved the 2007 Retail Rate Plan for the years 2008 through 2010. Under the 2007 Retail Rate Plan, the Company's earnings will continue to be evaluated against a retail return on common equity (ROE) range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to an ECCR tariff. The Company agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation and other investments, as well as increased operating costs. In addition, the ECCR tariff was implemented to allow for the recovery of costs for required environmental projects mandated by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008.

The Company is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In June 2006, the Georgia PSC approved an increase in the Company's total annual billings of approximately $400 million.

In February 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million effective March 1, 2007. On May 20, 2008, the Georgia PSC approved an additional increase of approximately $222 million effective June 1, 2008. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. As of December 31, 2008, the Company had a total under recovered fuel cost balance of approximately $764.4 million, of which approximately $223.9 million is not included in current rates.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Approximately $425.6 million of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets at December 31, 2008. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Georgia State Income Tax Credits

The Company's 2005 through 2008 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, these claims could have a significant, and possibly material, positive effect on the Company's net income. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. The ultimate outcome of this matter cannot now be determined. See Note 3 under "Income Tax Matters" and Note 5 under "Unrecognized Tax Benefits" for additional information.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service (IRS) has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Nuclear

Construction

In August 2006, Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 to the financial statements for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units.

On April 8, 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, the Company submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. The Company's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In connection with the certification application, the Company has requested Georgia PSC approval to include the construction work in progress accounts for Plant Vogtle Units 3 and 4 in rate base and allow the Company to recover financing costs during the construction period.

On February 11, 2009, the Georgia State Senate passed Senate Bill 31 that would allow the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. A similar bill is being considered in the Georgia State House of Representatives.

If the Company is not permitted to recover these costs during the construction period, the estimated capital expenditures would increase by approximately $144 million in 2011. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 7 to the financial statements under "Construction Program" for these forecasted capital expenditures.

The ultimate outcome of these matters cannot now be determined.

Relicensing

The NRC operating licenses for Plant Vogtle Units 1 and 2 currently expire in January 2027 and February 2029, respectively. In June 2007, the Company filed an application with the NRC to extend the licenses for Plant Vogtle Units 1 and 2 for an additional 20 years. The Company anticipates the NRC may make a decision regarding the license extension for Plant Vogtle in 2009.

Other Matters

The Company has initiated a voluntary attrition plan under which participating employees may elect to resign from their positions as of March 31, 2009. Approximately 700 employees who have indicated an interest in participating in the plan have been selected by the Company and are permitted to resign and receive severance. Each participating employee who resigns under the plan will be entitled to receive a severance payment equal to his or her annual base salary, accrued vacation, and pro-rated bonus as of March 31, 2009. The Company will record a charge during the first quarter of 2009 in connection with the plan. The ultimate amount of the charge will be dependent on the total number of employees who elect to resign under the plan. Such charge could have a material impact on the Company's statements of income for the quarter ending March 31, 2009 and statements of cash flows for the six months ending June 30, 2009. The first quarter 2009 charge will generally be offset with lower salary costs for the remainder of the year and is not expected to have a material impact on the Company's financial statements for the year ending December 31, 2009.

The Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. 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 IRS or Georgia DOR 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 new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. The Company has continued to issue commercial paper at reasonable rates. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension and nuclear decommissioning trust funds declined in value as of December 31, 2008. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future fund performance and cannot be determined at this time. The Company does not expect any changes to funding obligations to the nuclear decommissioning trusts at this time.

Cash flow from operations totaled $1.7 billion in 2008, an increase of $279.2 million from 2007, primarily due to higher retail operating revenues partially offset by higher inventory additions. Cash flow from operations in 2007 totaled $1.4 billion, an increase of $248.5 million from 2006, primarily due to higher retail revenues primarily related to higher fuel cost recovery revenues and less cash used for working capital primarily from lower inventory additions and increases in other current liabilities. Cash flow from operations increased $117.4 million in 2006, primarily from increased retail operating revenues partially offset by higher fuel inventories and an increase in under recovered deferred fuel costs.

Net cash used for investing activities totaled $1.9 billion, $1.9 billion, and $1.2 billion in 2008, 2007, and 2006, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards, construction of generation, transmission and distribution facilities, and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, capital contributions from Southern Company, and the issuance of long and short-term debt and preference stock.

Cash provided from financing activities totaled $309.8 million, $429.7 million, and $46.4 million for 2008, 2007, and 2006, respectively. These totals are primarily related to additional issuances of senior notes in 2008 and 2007, and the issuance of short-term debt in 2006. The statements of cash flows provide additional details. See "Financing Activities" herein.

Significant balance sheet changes in 2008 include a $1.1 billion increase in long-term debt primarily to replace short-term debt and provide funds for the Company's continuous construction program and an increase in total property, plant, and equipment of $1.3 billion. Other significant balance sheet changes include a decrease of $1.0 billion in prepaid pension costs, an increase of $908 million in other regulatory assets, and a decrease of $462 million in other regulatory liabilities primarily attributable to the decline in market value of the Company's pension trust fund. Significant balance sheet changes in 2007 include a $726 million increase in long-term debt and a $221 million increase in preferred and preference stock primarily to replace short-term debt and provide funds for the

Company's continuous construction programs. Other balance sheet changes in 2007 include an increase in total property, plant and equipment of $1.3 billion and a $206 million decrease in the under recovered fuel balance.

The Company's ratio of common equity to total capitalization – including short-term debt – was 46.5% in 2008, 47.5% in 2007, and 48.6% in 2006. The Company has received investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference stock. See SELECTED FINANCIAL AND OPERATING DATA for additional information regarding the Company's security ratings.

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, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approvals, and other factors. The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source for under recovered fuel costs and to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, at December 31, 2008 the Company had credit arrangements with banks totaling $1.3 billion. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

At December 31, 2008, bank credit arrangements were as follows:

		Expires	
Total	Unused	2009	2012
	(in millions)		
$1,345	$1,333	$225	$1,120

Of the credit arrangements that expire in 2009, $40 million allow for the execution of term loans for an additional two-year period.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefit of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2008, the Company had $256.3 million of outstanding commercial paper and a $100 million short-term bank loan outstanding.

Financing Activities

During 2008, the Company issued $1.0 billion of senior notes and incurred $312 million of obligations related to the issuance of pollution control revenue bonds. The issuances were used to reduce the Company's short-term indebtedness, fund senior note maturities totaling $198 million, redeem pollution control revenue bonds totaling $259 million, and fund the Company's ongoing construction program.

During 2008, the Company settled interest rate hedges of $325 million related to the issuance of senior notes at a loss of $20 million. Additionally, interest rate hedges of $100 million were settled early at a loss of $2 million related to counterparty credit issues.

In 2008, the Company converted its entire $819 million of obligations related to auction rate pollution control revenue bonds from auction rate modes to other interest rate modes. Initially, approximately $332 million of the auction rate pollution control revenue bonds were converted to fixed interest rate modes and approximately $487 million were converted to variable rate modes. The Company subsequently converted approximately $203 million of its variable rate pollution control revenue bonds to fixed interest rate modes. The Company also incurred obligations related to the issuance of $53 million of pollution control revenue bonds for the Company's Plant Hammond project. At December 31, 2008 the trustee held $22.4 million of the proceeds, which will be transferred to the Company for reimbursement of project costs.

In September 2008, the Company was required to purchase a total of approximately $76.6 million of variable rate pollution control revenue bonds that were tendered by investors. The Company subsequently remarketed $74.5 million of the tendered bonds. The remaining $2.1 million were extinguished.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Subsequent to December 31, 2008, the Company issued $500 million of Series 2009A 5.95% Senior Notes due February 1, 2039. The proceeds were used by the Company to repay at maturity $150 million aggregate principal amount of the Company's Series U Floating Rate Senior Notes due February 7, 2009, to repay a portion of short-term indebtedness, and for general corporate purposes. The Company settled $100 million of hedges related to the issuance at a loss of approximately $16 million.

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- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and for construction of new generation. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $27 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $961 million. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, where possible, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps and other derivatives that have been designated as hedges. These derivatives have a notional amount of $851 million and are related to anticipated debt issuances and certain variable rate debt over the next two years. The weighted average interest rate on $291 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2009 was 2.24%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3 million at January 1, 2009. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

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

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

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (0.4)**	$ (38.0)
Contracts realized or settled	**(68.5)**	41.6
Current period changes[(a)]	**(44.3)**	(4.0)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (113.2)**	$ (0.4)

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

The decrease in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2008 was $112.8 million, substantially all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, the Company had a net hedge volume of 59.3 billion cubic feet (Bcf) with a weighted average contract cost approximately $1.96 per million British thermal units (mmBtu) above market prices, compared to 44.1 Bcf at December 31, 2007 with a weighted average contract cost approximately $0.02 per mmBtu above market prices. These natural gas hedges are designated as regulatory hedges.

Energy-related derivative contracts which are designated as regulatory hedges relate to the Company's fuel hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism.

Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Unrealized pre-tax gains/(losses) recognized in income for energy-related derivative contracts that are not hedges were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	**$ -**	**$ -**	**$ -**	**$ -**
Level 2	**(113.2)**	**(80.7)**	**(32.4)**	**(0.1)**
Level 3	**-**	**-**	**-**	**-**
Fair value of contracts outstanding at end of period	**$ (113.2)**	**$ (80.7)**	**$ (32.4)**	**$ (0.1)**

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 10 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.8 billion for 2009, $2.6 billion for 2010, and $2.6 billion for 2011. This estimate assumes the Company's current request to include construction work in progress for Plant Vogtle Units 3 and 4 in rates is granted by the Georgia PSC or the Georgia legislature, beginning in 2011. If not, the estimate will increase by approximately $144 million in 2011. Environmental expenditures included in these estimated amounts are $472 million, $334 million, and $399 million for 2009, 2010, and 2011, respectively. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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

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

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

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Uncertain Timing [(d)]	Total
			(in millions)			
Long-term debt[(a)] –						
Principal	$ 280	$ 667	$ 734	$ 5,612	$ -	$ 7,293
Interest	354	677	636	5,711	-	7,378
Preferred and preference stock dividends[(b)]	17	35	35	-	-	87
Energy-related derivative obligations[(c)]	85	33	-	-	-	118
Interest derivatives	21	-	-	-	-	21
Operating leases	43	65	32	28	-	168
Unrecognized tax benefits and interest[(d)]	142	-	-	-	9	151
Purchase commitments[(e)] –						
Capital[(f)]	2,615	4,942	-	-	-	7,557
Limestone [(g)]	10	34	31	37	-	112
Coal	2,497	3,713	1,406	1,999	-	9,615
Nuclear fuel	139	219	199	33	-	590
Natural gas[(h)]	657	631	744	2,917	-	4,949
Purchased power	370	656	506	2,186	-	3,718
Long-term service agreements[(i)]	14	32	103	581	-	730
Trusts –						
Nuclear decommissioning[(j)]	3	7	7	53	-	70
Postretirement benefits[(k)]	39	81	-	-	-	120
Total	$7,286	$11,792	$4,433	$ 19,157	$ 9	$ 42,677

(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, 2009, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

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

(d) The timing related to the realization of $9 million in unrecognized tax benefits and interest payments cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. Of the total $151 million, $81 million is the estimated cash payment. See Note 3 and Note 5 to the financial statements for additional information.

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

(f) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

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

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

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

(j) Projections of nuclear decommissioning trust contributions are based on the 2007 Retail Rate Plan.

(k) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust fund are included in the table. 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 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, fuel cost recovery and other rate actions, environmental regulations and expenditures, the Company's projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, access to sources of capital, the impacts of the adoption of new accounting rules, estimated sales and purchases under new power sale and purchase agreements, 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, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population, business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- regulatory approvals related to the potential Plant Vogtle expansion, including Georgia PSC and NRC approvals;
- 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 and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Retail revenues	**$7,286,345**	$6,498,003	$6,205,620
Wholesale revenues --			
Non-affiliates	**568,797**	537,913	551,731
Affiliates	**286,219**	277,832	252,556
Other revenues	**270,191**	257,904	235,737
Total operating revenues	**8,411,552**	7,571,652	7,245,644
Operating Expenses:			
Fuel	**2,812,417**	2,640,526	2,233,029
Purchased power --			
Non-affiliates	**442,951**	332,064	332,606
Affiliates	**962,100**	718,327	812,433
Other operations and maintenance	**1,580,922**	1,561,736	1,560,469
Depreciation and amortization	**636,970**	511,180	498,754
Taxes other than income taxes	**316,219**	291,136	298,824
Total operating expenses	**6,751,579**	6,054,969	5,736,115
Operating Income	**1,659,973**	1,516,683	1,509,529
Other Income and (Expense):			
Allowance for equity funds used during construction	**95,294**	68,177	31,524
Interest income	**7,219**	3,560	2,459
Interest expense, net of amounts capitalized	**(345,416)**	(343,462)	(317,947)
Other income (expense), net	**(9,258)**	14,705	8,833
Total other income and (expense)	**(252,161)**	(257,020)	(275,131)
Earnings Before Income Taxes	**1,407,812**	1,259,663	1,234,398
Income taxes	**487,504**	417,521	442,334
Net Income	**920,308**	842,142	792,064
Dividends on Preferred and Preference Stock	**17,381**	6,006	4,839
Net Income After Dividends on Preferred and Preference Stock	**$902,927**	$836,136	$787,225

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$ 920,308**	$ 842,142	$ 792,064
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**758,283**	616,796	588,428
Deferred income taxes and investment tax credits, net	**170,958**	(78,010)	16,159
Deferred revenues	**122,964**	4,871	(136)
Allowance for equity funds used during construction	**(95,294)**	(68,177)	(31,524)
Pension, postretirement, and other employee benefits	**(3,243)**	8,836	18,604
Stock based compensation expense	**4,200**	5,977	5,805
Hedge settlements	**(22,949)**	12,121	-
Other, net	**909**	18,550	4,592
Changes in certain current assets and liabilities --			
Receivables	**(82,995)**	134,276	1,193
Fossil fuel stock	**(91,536)**	(1,211)	(194,256)
Materials and supplies	**(20,021)**	(32,998)	31,317
Prepaid income taxes	**(14,885)**	10,002	1,060
Other current assets	**(18,460)**	(4,359)	774
Accounts payable	**(56,126)**	22,626	(85,189)
Accrued taxes	**117,524**	(33,320)	82,735
Accrued compensation	**21,525**	(30,039)	(10,328)
Other current liabilities	**16,789**	20,703	(21,054)
Net cash provided from operating activities	**1,727,951**	1,448,786	1,200,244
Investing Activities:			
Property additions	**(1,847,952)**	(1,765,344)	(1,219,498)
Investment in restricted cash from pollution control bonds	**-**	(59,525)	-
Distribution of restricted cash from pollution control bonds	**32,675**	-	-
Nuclear decommissioning trust fund purchases	**(419,086)**	(448,287)	(464,274)
Nuclear decommissioning trust fund sales	**412,206**	441,407	457,394
Cost of removal net of salvage	**(62,722)**	(47,565)	(33,620)
Change in construction payables, net of joint owner portion	**2,639**	24,893	35,075
Other	**(38,199)**	(25,479)	(16,005)
Net cash used for investing activities	**(1,920,439)**	(1,879,900)	(1,240,928)
Financing Activities:			
Increase (decrease) in notes payable, net	**(358,497)**	(17,690)	406,768
Proceeds --			
Senior notes	**1,000,000**	1,500,000	150,000
Preferred and preference stock	**-**	225,000	-
Pollution control revenue bonds	**386,485**	190,800	153,910
Capital contributions from parent company	**272,894**	322,448	312,544
Other long-term debt	**301,100**	-	-
Redemptions --			
Pollution control revenue bonds	**(335,605)**	-	(153,910)
Capital leases	**(1,125)**	(2,185)	(136)
Senior notes	**(198,097)**	(300,000)	(150,000)
First mortgage bonds	**-**	-	(20,000)
Preferred and preference stock	**-**	-	(14,569)
Other long-term debt	**-**	(762,887)	-
Payment of preferred and preference stock dividends	**(17,016)**	(3,143)	(2,958)
Payment of common stock dividends	**(721,200)**	(689,900)	(630,000)
Other	**(19,104)**	(32,787)	(5,253)
Net cash provided from financing activities	**309,835**	429,656	46,396
Net Change in Cash and Cash Equivalents	**117,347**	(1,458)	5,712
Cash and Cash Equivalents at Beginning of Year	**15,392**	16,850	11,138
Cash and Cash Equivalents at End of Year	**$ 132,739**	$ 15,392	$ 16,850
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $39,807, $28,668, and $12,530 capitalized, respectively)	**$309,264**	$317,938	$317,536
Income taxes (net of refunds)	**279,904**	456,852	398,735

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

BALANCE SHEETS
At December 31, 2008 and 2007
Georgia Power Company 2008 Annual Report

Assets	**2008**	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 132,739**	$ 15,392
Restricted cash	**22,381**	48,279
Receivables --		
Customer accounts receivable	**554,220**	491,389
Unbilled revenues	**147,978**	137,046
Under recovered regulatory clause revenues	**338,780**	384,538
Other accounts and notes receivable	**97,898**	147,498
Affiliated companies	**13,091**	21,699
Accumulated provision for uncollectible accounts	**(10,732)**	(7,636)
Fossil fuel stock, at average cost	**484,757**	393,222
Materials and supplies, at average cost	**356,537**	337,652
Vacation pay	**71,217**	69,394
Prepaid income taxes	**65,987**	51,101
Other	**182,425**	55,169
Total current assets	**2,457,278**	2,144,743
Property, Plant, and Equipment:		
In service	**23,975,262**	22,011,215
Less accumulated provision for depreciation	**9,101,474**	8,696,668
	14,873,788	13,314,547
Nuclear fuel, at amortized cost	**278,412**	198,983
Construction work in progress	**1,434,989**	1,797,642
Total property, plant, and equipment	**16,587,189**	15,311,172
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**57,163**	53,813
Nuclear decommissioning trusts, at fair value	**460,430**	588,952
Other	**40,945**	47,914
Total other property and investments	**558,538**	690,679
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**572,528**	532,539
Prepaid pension costs	**-**	1,026,985
Deferred under recovered regulatory clause revenues	**425,609**	307,294
Other regulatory assets	**1,449,352**	541,014
Other	**265,174**	268,335
Total deferred charges and other assets	**2,712,663**	2,676,167
Total Assets	**$22,315,668**	$20,822,761

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

BALANCE SHEETS
At December 31, 2008 and 2007
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Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 280,443**	$ 198,576
Notes payable	**357,095**	715,591
Accounts payable --		
Affiliated	**260,545**	236,332
Other	**422,485**	463,945
Customer deposits	**186,919**	171,553
Accrued taxes --		
Income taxes	**70,916**	68,782
Unrecognized tax benefits	**128,712**	-
Other	**278,171**	219,585
Accrued interest	**79,432**	74,674
Accrued vacation pay	**57,643**	56,303
Accrued compensation	**135,191**	114,974
Other	**249,609**	103,225
Total current liabilities	**2,507,161**	2,423,540
Long-term Debt (See accompanying statements)	**7,006,275**	5,937,792
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,064,580**	2,850,655
Deferred credits related to income taxes	**140,933**	146,886
Accumulated deferred investment tax credits	**256,218**	269,125
Employee benefit obligations	**882,965**	678,826
Asset retirement obligations	**688,019**	663,503
Other cost of removal obligations	**396,947**	414,745
Other regulatory liabilities	**115,865**	577,642
Other	**111,505**	158,670
Total deferred credits and other liabilities	**5,657,032**	5,760,052
Total Liabilities	**15,170,468**	14,121,384
Preferred and Preference Stock (See accompanying statements)	**265,957**	265,957
Common Stockholder's Equity (See accompanying statements)	**6,879,243**	6,435,420
Total Liabilities and Stockholder's Equity	**$22,315,668**	$20,822,761
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
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	2008	2007	2008	2007
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.88% due 2044	**$ 206,186**	$ 206,186		
Long-term notes payable --				
6.55% due May 15, 2008	**-**	45,000		
4.10% due 2009	**125,300**	125,000		
Variable rate (5.00% at 1/1/08) due 2008	**-**	150,000		
Variable rate (2.3288% at 1/1/09) due 2009	**150,000**	150,000		
Variable rate (2.42% at 1/1/09) due 2010	**250,000**	-		
Variable rate (2.35% at 1/1/09) due 2011	**300,000**	-		
4.00% to 5.57% due 2011	**101,100**	100,000		
5.125% due 2012	**200,000**	200,000		
4.90% to 6.00% due 2013	**525,000**	125,000		
5.25% to 8.20% due 2015-2048	**3,421,903**	3,075,000		
Total long-term notes payable	**5,073,303**	3,970,000		
Other long-term debt --				
Pollution control revenue bonds:				
1.95% to 5.75% due 2016-2048	**1,309,190**	774,370		
Variable rate (1.05% at 1/1/09) due 2011	**8,330**	10,450		
Variable rate (0.80% to 3.00% at 1/1/09) due 2016-2041	**628,005**	1,109,825		
Total other long-term debt	**1,945,525**	1,894,645		
Capitalized lease obligations	**67,948**	70,733		
Unamortized debt discount	**(6,244)**	(5,196)		
Total long-term debt (annual interest requirement -- $354.0 million)	**7,286,718**	6,136,368		
Less amount due within one year	**280,443**	198,576		
Long-term debt excluding amount due within one year	**7,006,275**	5,937,792	**49.5%**	47.0%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**44,991**	44,991		
Non-cumulative preference stock				
$100 par value -- 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**220,966**	220,966		
Total preferred and preference stock (annual dividend requirement -- $17.4 million)	**265,957**	265,957	**1.9**	2.1
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398,473**	398,473		
Paid-in capital	**3,655,731**	3,374,777		
Retained earnings	**2,857,789**	2,676,063		
Accumulated other comprehensive income (loss)	**(32,750)**	(13,893)		
Total common stockholder's equity	**6,879,243**	6,435,420	**48.6**	50.9
Total Capitalization	**$14,151,475**	$12,639,169	**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, 2008, 2007, and 2006
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	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$398,473	$2,717,539	$2,372,637	$(36,566)	$5,452,083
Net income after dividends on preferred stock	-	-	787,225	-	787,225
Capital contributions from parent company	-	322,306	-	-	322,306
Other comprehensive income	-	-	-	5,184	5,184
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	19,489	19,489
Cash dividends on common stock	-	-	(630,000)	-	(630,000)
Other	-	-	(36)	-	(36)
Balance at December 31, 2006	398,473	3,039,845	2,529,826	(11,893)	5,956,251
Net income after dividends on preferred and preference stock	-	-	836,136	-	836,136
Capital contributions from parent company	-	334,931	-	-	334,931
Other comprehensive loss	-	-	-	(2,000)	(2,000)
Cash dividends on common stock	-	-	(689,900)	-	(689,900)
Other	-	1	1	-	2
Balance at December 31, 2007	**398,473**	**3,374,777**	**2,676,063**	**(13,893)**	**6,435,420**
Net income after dividends on preferred and preference stock	**-**	**-**	**902,927**	**-**	**902,927**
Capital contributions from parent company	**-**	**280,954**	**-**	**-**	**280,954**
Other comprehensive loss	**-**	**-**	**-**	**(18,857)**	**(18,857)**
Cash dividends on common stock	**-**	**-**	**(721,200)**	**-**	**(721,200)**
Other	**-**	**-**	**(1)**	**-**	**(1)**
Balance at December 31, 2008	**$398,473**	**$3,655,731**	**$2,857,789**	**$(32,750)**	**$6,879,243**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2008, 2007, and 2006
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	2008	2007	2006
		(in thousands)	
Net income after dividends on preferred and preference stock	**$902,927**	$836,136	$787,225
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(13,150), $(1,831), and $(935), respectively	**(20,846)**	(2,938)	(1,454)
Reclassification adjustment for amounts included in net income, net of tax of $1,255, $278, and $(441), respectively	**1,989**	441	(700)
Marketable securities:			
Changes in fair value, net of tax of $-, $291, and $(494), respectively	**-**	497	(817)
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $-, and $5,143, respectively	**-**	-	8,155
Total other comprehensive income (loss)	**(18,857)**	(2,000)	5,184
Comprehensive Income	**$884,070**	$834,136	$792,409

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), the Company, Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary.

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

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. The statements of income have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." Due to materiality in the current period, the statements of cash flows for the prior periods presented were modified within the operating activities section to separately report the amount of "Deferred revenues" and "Hedge settlements" previously included in "Other, net" while the line item "Tax benefit of stock options" was collapsed into "Other, net." Within the financing activities section of the statements of cash flows in the prior periods, the amount of "Gross excess tax benefit of stock options" was combined into "Other." These reclassifications had no effect on total assets, net income, or cash flows.

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, digital wireless communications, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $490 million in 2008, $449 million in 2007, and $393 million in 2006. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $410 million in 2008, $380 million in 2007, and $348 million in 2006.

The Company had an agreement with Southern Power under which the Company operated and maintained Southern Power's Plants Dahlberg, Franklin, and Wansley at cost. In August 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power specifically requested services. Billings under these agreements with Southern Power amounted to $1.9 million in 2008, $6.8 million in 2007, and $5.4 million in 2006.

Southern Company's 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produced synthetic fuel, was terminated in July 2006. The Company had an agreement with an indirect subsidiary of Southern Company that provided services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $85 million in 2007, and $76 million in 2006. In addition, the Company purchased synthetic fuel from AFP for use at Plant Branch. Synthetic fuel purchases totaled $278 million in both 2007 and 2006. The related party transactions and synthetic fuel purchases were terminated as of December 31, 2007.

The Company has entered into several power purchase agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $480 million, $440 million, and $407 million in 2008, 2007, and 2006, respectively. Additionally, the Company had $25 million and $26 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2008 and 2007, respectively. See Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer. Under this agreement, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $8.1 million in 2008, $5.1 million in 2007, and $8.0 million in 2006. See Note 4 for additional information.

In 2008, the Company purchased a compressor assembly from Southern Power for $3.9 million.

In 2007, the Company sold equipment at cost to Gulf Power for $4.0 million.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. The Company provided no significant storm assistance to affiliates in 2008, 2007, or 2006.

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

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

Regulatory Assets and Liabilities

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

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

	2008	2007	Note
	(in millions)		
Deferred income tax charges	**$ 573**	$ 533	(a)
Loss on reacquired debt	**165**	175	(b)
Vacation pay	**71**	69	(c)
Underfunded retiree benefit plans	**903**	235	(e)
Fuel-hedging (realized and unrealized) losses	**130**	14	(f)
Nuclear early site permit	**49**	28	(h)
Other regulatory assets	**160**	133	(d)
Asset retirement obligations	**209**	41	(a)
Other cost of removal obligations	**(397)**	(415)	(a)
Deferred income tax credits	**(141)**	(147)	(a)
Overfunded retiree benefit plans	**-**	(540)	(e)
Environmental compliance cost recovery	**(135)**	-	(g)
Other regulatory liabilities	**(14)**	(21)	(d)
Total assets (liabilities), net	**$1,573**	$ 105	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

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

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

(e) Recovered and amortized over the average remaining service period which may range up to 16 years. See Note 2 for additional information.

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

(g) This balance represents deferred revenue associated with the Environmental Compliance Cost Recovery (ECCR) tariff established in the 2007 Retail Rate Plan (as defined below). The recovery of the forecasted environmental compliance costs was levelized to collect equal annual amounts between January 1, 2008 and December 31, 2010 under the tariff.

(h) This balance represents deferred costs incurred in support of preparation and completion of an early site permit and combined construction and operating license (COL) for two additional nuclear generating units at Plant Vogtle (Units 3 and 4). The costs will be capitalized to construction work in progress upon certification by the Georgia PSC.

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 or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs and the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

Retail fuel cost recovery rates require periodic filings with the Georgia PSC. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery." The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

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:

	2008	2007
	(in millions)	
Generation	**$ 11,478**	$10,180
Transmission	**3,764**	3,593
Distribution	**7,409**	6,985
General	**1,296**	1,225
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 23,975**	$22,011

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for Plants Vogtle and Hatch, respectively. Also, in accordance with the Georgia PSC, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2008 and 2.6% in 2007 and 2006. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2008, the Company's depreciation rates were revised by the Georgia PSC.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the Company's retail rate plan for the three years ended December 31, 2007 (2004 Retail Rate Plan), the Company was ordered to recognize Georgia PSC–certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. The Company recorded credits to amortization of $19 million and $14 million in 2007 and 2006, respectively. The retail rate plan for the three years ending December 31, 2010 (2007 Retail Rate Plan) did not include a similar order. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plants Hatch and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2008 was $460 million. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been recorded because 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 the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under FASB Statement No. 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2008	2007
	(in millions)	
Balance beginning of year	**$ 664**	$ 627
Liabilities incurred	**4**	-
Liabilities settled	**(1)**	(3)
Accretion	**41**	40
Cash flow revisions	**(18)**	-
Balance end of year	**$ 690**	$ 664

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as of December 31, 2008 as trading securities pursuant to FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115).

On January 1, 2008, the Company adopted 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 elected the fair value option only for investment securities held in the Funds. The Funds are included in the balance sheets at fair value, as disclosed in Note 10.

Management elected to continue to record the Funds at fair value because management believes that fair value best represents the nature of the Funds. Management has delegated day-to-day management of the investments in the Funds to unrelated third party managers with oversight by Southern Company and Company management. The managers of the Funds are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the investment return on the Funds' investments. Because of the Company's inability to choose to hold securities that have experienced unrealized losses until recovery of their value, all unrealized losses incurred during 2006 and 2007, prior to the adoption of SFAS No. 159, were considered other-than-temporary impairments under SFAS No. 115.

The adoption of SFAS No. 159 had no impact on the results of operations, cash flows, or financial condition of the Company. For all periods presented, all gains and losses, whether realized, unrealized, or identified as other-than-temporary, have been and will continue to be recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Fair value adjustments, realized gains, and other-than-temporary impairment losses are determined on a specific identification basis.

At December 31, 2008, investment securities in the Funds totaled $459.1 million consisting of equity securities of $261.4 million, debt securities of $187.3 million, and $10.4 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

At December 31, 2007, investment securities in the Funds totaled $589.0 million consisting of equity securities of $402.4 million, debt securities of $171.8 million, and $14.8 million of other securities. Unrealized gains were $125.5 million for equity securities and $4.8 million for debt securities. Other-than-temporary impairments were $(12.2) million for equity securities and $(1.8) million for debt securities.

Sales of the securities held in the Funds resulted in cash proceeds of $412.2 million, $441.4 million, and $457.4 million in 2008, 2007, and 2006, respectively, all of which were re-invested. For 2008, fair value reductions, including reinvested interest and dividends, were $(143.9) million, of which $(151.0) million related to securities held in the Funds at December 31, 2008. Realized gains and other-than-temporary impairment losses were $43.7 million and $(39.1) million, respectively, in 2007 and $17.8 million and $(12.1) million, respectively, in 2006. While the investment securities held in the Funds are reported as trading securities from the perspective of SFAS No. 115, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2006. The site study costs and accumulated provisions for decommissioning as of December 31, 2008 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2061	2051
	(in millions)	
Site study costs:		
Radiated structures	$ 544	$ 507
Non-radiated structures	46	67
Total site study costs	$ 590	$ 574
Accumulated provision	$ 280	$ 168

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities. Under the 2004 Retail Rate Plan, the annual decommissioning costs for ratemaking were $7 million for Plant Vogtle for 2006 and 2007. Under the 2007 Retail Rate Plan, effective for the years 2008 through 2010, the annual decommissioning cost for ratemaking is $3 million for Plant Vogtle. Based on estimates approved in the 2007 Retail Rate Plan, the Company projected the external trust funds for Plant Hatch would be adequate to meet the decommissioning obligations with no further contributions. The NRC estimates are $495 million and $334 million for Plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.9% and an estimated trust earnings rate of 4.9%. Another significant assumption was that the operating licenses for Plant Vogtle would remain at 40 years until a 20-year extension requested by the Company in June 2007 is authorized by the NRC. The Company anticipates the NRC will make a decision regarding the license extension for Plant Vogtle in 2009.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2008, 2007, and 2006, the average AFUDC rates were 8.2%, 8.4%, and 8.3%, respectively, and AFUDC capitalized was $135.1 million, $96.8 million, and $44.1 million, respectively. AFUDC and interest capitalized, net of taxes were 13.3%, 10.3%, and 5.0% of net income after dividends on preferred and preference stock for 2008, 2007, and 2006, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. Under the 2004 Retail Rate Plan, the Company accrued $6.6 million annually that was recoverable through base rates. Effective

January 1, 2008, the Company is accruing $21.4 million annually under the 2007 Retail Rate Plan. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

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

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 (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company's financial instruments for which the carrying amount did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2008	**$ 7,219**	**$ 7,096**
2007	$ 6,066	$ 5,969

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 10 for all other items recognized at fair value in the financial statements.

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 prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158) the minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt in the balance sheets. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds trusts to the extent required by the FERC. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $39 million.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to SFAS No. 158, the Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, the Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $10 million and an increase in prepaid pension costs of approximately $10 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.1 billion in 2008 and $2.0 billion in 2007. Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,178**	$ 2,136
Service cost	**62**	51
Interest cost	**167**	126
Benefits paid	**(133)**	(98)
Plan amendments	**-**	15
Actuarial (gain) loss	**(36)**	(52)
Balance at end of year	**2,238**	2,178
Change in plan assets		
Fair value of plan assets at beginning of year	**3,073**	2,710
Actual return (loss) on plan assets	**(910)**	456
Employer contributions	**8**	5
Benefits paid	**(133)**	(98)
Fair value of plan assets at end of year	**2,038**	3,073
Funded status at end of year	**(200)**	895
Fourth quarter contributions	**-**	2
(Accrued liability) prepaid pension asset	**$ (200)**	$ 897

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $2.1 billion and $128 million, respectively. All pension 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 year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	36%	**34%**	38%
International equity	24	**23**	24
Fixed income	15	**14**	15
Real estate	15	**19**	16
Private equity	10	**10**	7
Total	100%	**100%**	100%

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

	2008	2007
	(in millions)	
Prepaid pension costs	**$ -**	$ 1,027
Other regulatory assets	**642**	64
Current liabilities, other	**(7)**	(7)
Other regulatory liabilities	**-**	(540)
Employee benefit obligations	**(193)**	(123)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	**Net (Gain) Loss**
Balance at December 31, 2008:	*(in millions)*	
Regulatory asset	**$ 87**	**$ 555**
Total	**$ 87**	**$ 555**
Balance at December 31, 2007:	*(in millions)*	
Regulatory asset	$ 24	$ 40
Regulatory liabilities	81	(621)
Total	$ 105	$ (581)
Estimated amortization in net periodic pension cost in 2009:	*(in millions)*	
Regulatory assets	$ 14	$ 2
Total	$ 14	$ 2

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in millions)	
Balance at December 31, 2006	$ 56	$ (218)
Net (gain) loss	(1)	(311)
Change in prior service costs	15	-
Reclassification adjustments:		
Amortization of prior service costs	(3)	(11)
Amortization of net gain	(3)	-
Total reclassification adjustments	(6)	(11)
Total change	8	(322)
Balance at December 31, 2007	$ 64	$ (540)
Net (gain) loss	**585**	**554**
Change in prior service costs	**-**	**-**
Reclassification adjustments:		
Amortization of prior service costs	**(4)**	**(14)**
Amortization of net gain	**(3)**	**-**
Total reclassification adjustments	**(7)**	**(14)**
Total change	**578**	**540**
Balance at December 31, 2008	**$ 642**	**$ -**

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

	2008	2007	2006
		(in millions)	
Service cost	**$ 49**	$ 51	$ 53
Interest cost	**134**	126	117
Expected return on plan assets	**(211)**	(195)	(184)
Recognized net (gain) loss	**3**	3	6
Net amortization	**14**	14	8
Net periodic pension cost (income)	**$ (11)**	$ (1)	$ -

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, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2009	$ 118
2010	124
2011	130
2012	136
2013	143
2014 to 2018	841

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 798**	$ 807
Service cost	**13**	10
Interest cost	**61**	47
Benefits paid	**(47)**	(35)
Actuarial (gain) loss	**(57)**	(33)
Retiree drug subsidy	**4**	2
Balance at end of year	**772**	798
Change in plan assets		
Fair value of plan assets at beginning of year	**427**	388
Actual return on plan assets	**(131)**	54
Employer contributions	**59**	18
Benefits paid	**(43)**	(33)
Fair value of plan assets at end of year	**312**	427
Funded status at end of year	**(460)**	(371)
Fourth quarter contributions	**-**	31
Accrued liability (recognized in the balance sheets)	**$ (460)**	$ (340)

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

	Target	**2008**	2007
Domestic equity	43%	**38%**	46%
International equity	21	**21**	23
Fixed income	31	**35**	25
Real estate	3	**4**	4
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2008	2007
	(in millions)	
Other regulatory assets	**$ 261**	$ 171
Employee benefit obligations	**(460)**	(340)

Presented below are the amounts included in regulatory assets at December 31, 2008 and 2007 related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2008:			
Regulatory assets	**$ 20**	**$ 198**	**$ 43**
Balance at December 31, 2007:			
Regulatory assets	$ 22	$ 94	$ 55
Estimated amortization in net periodic postretirement benefit cost in 2009:			
Regulatory assets	$ 2	$ 4	$ 9

The change in the balance of regulatory assets related to the other postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 is presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2006	$ 254
Net (gain) loss	(64)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(9)
Amortization of prior service costs	(2)
Amortization of net gain	(8)
Total reclassification adjustments	(19)
Total change	(83)
Balance at December 31, 2007	$ 171
Net (gain) loss	**110**
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	**(11)**
Amortization of prior service costs	**(3)**
Amortization of net gain	**(6)**
Total reclassification adjustments	**(20)**
Total change	**90**
Balance at December 31, 2008	**$ 261**

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

	2008	2007	2006
		(in millions)	
Service cost	**$ 10**	$ 10	$ 11
Interest cost	**50**	47	44
Expected return on plan assets	**(30)**	(26)	(25)
Net amortization	**16**	19	22
Net postretirement cost	**$ 46**	$ 50	$ 52

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $14 million, $14 million, and $16 million, respectively.

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

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2009	$ 45	$ (3)	$ 42
2010	50	(4)	46
2011	54	(5)	49
2012	57	(5)	52
2013	60	(6)	54
2014 to 2018	334	(41)	293

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	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 9.15% for 2009, decreasing gradually to 5.50% through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 61	$ 61
Service and interest costs	$ 4	$ 4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $25 million, $24 million, and $21 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S.District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities including the Company's Plants Bowen and Scherer. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against the Company has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to 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. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 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 all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where it was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve 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 $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. 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. The 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, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with 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.

Through 2007, the Company recovered environmental costs through its base rates. Beginning in 2005, such rates included an annual accrual of $5.4 million for environmental remediation. Beginning in January 2008, the Company is recovering environmental remediation costs through a new base rate tariff (see "Retail Regulatory Matters - Rate Plans" herein) that includes an annual accrual of $1.2 million for environmental remediation. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings. Under Georgia PSC ratemaking provisions, $22 million had previously been deferred in a regulatory liability account for use in meeting future environmental remediation costs of the Company and was amortized over a three-year period that ended December 31, 2007. As of December 31, 2008, the balance of the environmental remediation liability was $10.1 million.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated. The final outcome of these matters cannot now be determined. Based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

By letter dated September 30, 2008, the EPA advised the Company that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices from the EPA. The Company, along with other named PRPs, will participate in negotiations with the EPA to address cleanup of the site and reimbursement for the EPA's past expenditures related to work performed at the site. The ultimate outcome of this matter will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, it is not expected to have a material impact on the Company's financial statements.

FERC Matters

Market-Based Rate Authority

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

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $5.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

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

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008 the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

Income Tax Matters

The Company's 2005 through 2008 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. If the Company prevails, these claims could have a significant, and possibly material, positive effect on the Company's net income. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. The ultimate outcome of this matter cannot now be determined. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Retail Regulatory Matters

Merger

Effective July 1, 2006, Savannah Electric, which was also a wholly owned subsidiary of Southern Company, was merged into the Company. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements included herein now reflect the merger as though it had occurred on January 1, 2006.

Rate Plans

In December 2007, the Georgia PSC approved the 2007 Retail Rate Plan for the years 2008 through 2010. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation, and other investment, as well as increased operating costs. In addition, the new ECCR tariff was implemented to recover costs incurred for environmental projects required by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008. Under the 2007 Retail Rate Plan, the Company's earnings will continue to be evaluated against a retail return on equity (ROE) range of 10.25% to 12.25%. Two thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to the ECCR tariff. The Company agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. There were no refunds related to earnings for the year 2008.

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the Company. Under the terms of the 2004 Retail Rate Plan, the Company's earnings were evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% were applied to rate refunds, with the remaining one-third retained by the Company. Retail rates and customer fees increased by approximately $203 million effective January 1, 2005 to cover the higher costs of purchased power, operating and maintenance expenses, environmental compliance, and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2007, the Company refunded 2005 earnings above 12.25% retail ROE. There were no refunds related to earnings for the years 2006 and 2007.

The Company is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In June 2006, the Georgia PSC approved an increase in the Company's total annual billings of approximately $400 million.

In February 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million effective March 1, 2007. On May 20, 2008, the Georgia PSC approved an additional increase of approximately $222 million effective June 1, 2008. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. As of December 31, 2008, the Company had a total under recovered fuel cost balance of approximately $764.4 million, of which approximately $223.9 million is not included in current rates.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Approximately $425.6 million of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets at December 31, 2008.

Fuel Hedging Program

The Georgia PSC has approved a natural gas, oil procurement, and hedging program that allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels, subject to certain limits in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause. Annual net financial gains from the hedging program, through June 30, 2006, were shared with the retail customers receiving 75% and the Company retaining 25% of the total net gains. Effective July 1, 2006, the profit sharing framework related to the fuel hedging program was terminated. The Company realized net losses in 2008, 2007, and 2006 of $1.9 million, $68 million, and $66 million, respectively.

Nuclear Construction

In August 2006, Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia (Dalton) (collectively, Owners), filed an application with the NRC for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a COL for the new units.

On April 8, 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, the Company submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. The Company's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement. In June 2006, the Georgia PSC approved the Company's request to defer for future recovery early site permit and COL costs, of which the Company's portion is estimated to total approximately $53 million. At December 31, 2008 and 2007, approximately $49.0 million and $28.4 million, respectively, were included in deferred charges and other assets. Such costs will be included in construction work in progress if the project is certified by the Georgia PSC.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

Nuclear Fuel Disposal Costs

The Company has contracts with the United States, acting through the U.S. Department of Energy (DOE), which provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract.

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Hatch and Vogtle from 1998 through 2004. In July 2007, the government filed a motion for reconsideration, which was denied in November 2007. On January 2, 2008, the government filed an appeal, and on February 29, 2008, filed a motion to stay the appeal. On April 1, 2008, the court granted the government's motion to stay the appeal pending the court's decisions in three other similar cases already on appeal. Those cases were decided in August 2008. Based on the rulings in those cases, the appeal is expected to proceed in first quarter 2009.

On April 3, 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. On October 31, 2008, the court denied a similar request by the government to stay this proceeding. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2008 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Expanded wet storage capacity and construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice. The Company accounts for SEGCO using the equity method.

The Company's share of expenses included in purchased power from affiliates in the statements of income is as follows:

	2008	2007	2006
	(in millions)		
Energy	**$ 86**	$ 66	$ 58
Capacity	**41**	42	38
Total	**$ 127**	$ 108	$ 96

The Company owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2008 the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	**Company Ownership**	**Investment**	**Accumulated Depreciation**
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$ 3,303	$ 1,918
Plant Hatch (nuclear)	50.1	953	521
Plant Wansley (coal)	53.5	552	189
Plant Scherer (coal)			
Units 1 and 2	8.4	117	68
Unit 3	75.0	566	328
Rocky Mountain (pumped storage)	25.4	175	102
Intercession City (combustion-turbine)	33.3	12	3

At December 31, 2008, the portion of total construction work in progress related to Plants Wansley and Scherer was $114 million and $247 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

The transfer of the Plant McIntosh construction project from Southern Power to the Company in 2005 resulted in a deferred gain to Southern Power for federal income tax purposes. The Company is reimbursing Southern Power for the remaining balance of the related deferred taxes of $4.6 million as it is reflected in Southern Power's future taxable income. Of this amount, $3.8 million is included in Other Deferred Credits and $0.8 million is included in Affiliated Accounts Payable in the balance sheets at December 31, 2008.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power is reimbursing the Company for the remaining balance of the related deferred taxes of $8.3 million as it is reflected in the Company's future taxable income. Of this amount, $6.7 million is included in Other Deferred Debits and $1.6 million is included in Affiliated Accounts Receivable in the balance sheets at December 31, 2008.

Details of income tax provisions are as follows:

	2008	2007	2006
		(in millions)	
Federal –			
Current	**$ 284**	$ 442	$ 393
Deferred	**155**	(72)	7
	439	370	400
State –			
Current	**32**	54	33
Deferred	**16**	(6)	9
	48	48	42
Total	**$ 487**	$ 418	$ 442

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:

	2008	2007
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 2,554**	$ 2,376
Property basis differences	**594**	568
Employee benefit obligations	**174**	374
Fuel clause under recovery	**311**	281
Premium on reacquired debt	**67**	71
Regulatory assets associated with employee benefit obligations	**349**	123
Asset retirement obligations	**267**	257
Other	**72**	53
Total	**4,388**	4,103
Deferred tax assets –		
Federal effect of state deferred taxes	**189**	160
Employee benefit obligations	**457**	226
Other property basis differences	**127**	130
Other deferred costs	**99**	131
Other comprehensive income	**10**	2
Regulatory liabilities associated with employee benefit obligations	**-**	209
Unbilled fuel revenue	**42**	34
Asset retirement obligations	**267**	257
Environmental capital cost recovery	**52**	-
Other	**21**	35
Total	**1,264**	1,184
Total deferred tax liabilities, net	**3,124**	2,919
Portion included in current liabilities, net	**(60)**	(69)
Accumulated deferred income taxes	**$ 3,064**	$ 2,850

At December 31, 2008, tax-related regulatory assets were $573 million and tax-related regulatory liabilities were $141 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $13.0 million annually in 2008, 2007, and 2006. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	2.4	2.2
Non-deductible book depreciation	**0.9**	1.1	1.1
AFUDC equity	**(2.4)**	(1.9)	(0.9)
Donations	**-**	(1.7)	-
Other	**(1.1)**	(1.7)	(1.6)
Effective income tax rate	**34.6%**	33.2%	35.8%

The increase in 2008's effective tax rate is primarily the result of a decrease in donations for 2008 as a result of the significant Tallulah Gorge land donation in 2007 combined with an increase in non-taxable AFUDC equity.

In 2007, the Company donated 2,200 acres of land in the Tallulah Gorge State Park to the State of Georgia. The estimated value of this donation along with an increase in non-taxable AFUDC equity and available state tax credits as well as higher federal tax deductions caused a lower effective income tax rate for the year ended 2007, when compared to prior years. For additional information regarding litigation related to state tax credits, see Note 3 under "Income Tax Matters."

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. This increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $18.6 million over the 2006 deduction. The resulting additional tax benefit was $6.5 million. The IRS has not clearly defined a methodology for calculating this deduction. However, the Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits increased by $47.9 million, resulting in a balance of $137.1 million as of December 31, 2008.

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

	2008	2007
	(in millions)	
Unrecognized tax benefits at beginning of year	**$ 89.2**	$ 65.0
Tax positions from current periods	**47.0**	20.5
Tax positions from prior periods	**4.6**	3.7
Reductions due to settlements	**(3.7)**	-
Balance at end of year	**$ 137.1**	$ 89.2

The tax positions from current periods relate primarily to the Georgia state tax credits litigation and other miscellaneous uncertain tax positions. The reductions due to settlements relate to the agreement with the IRS regarding the production activities deduction methodology. See Note 3 under "Income Tax Matters" and "Effective Tax Rate" above for additional information.

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

	2008	2007	Change
		(in millions)	
Tax positions impacting the effective tax rate	$ 134.2	$ 86.1	$ 48.1
Tax positions not impacting the effective tax rate	2.9	3.1	(0.2)
Balance of unrecognized tax benefits	$ 137.1	$ 89.2	$ 47.9

The tax positions impacting the effective tax rate increase of $48.1 million primarily relate to Georgia state tax credit litigation at the Company. See Note 3 under "Income Tax Matters" for additional information.

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in millions)	
Interest accrued at beginning of year	$ 7.1	$ 2.7
Interest reclassified due to settlements	(0.3)	-
Interest accrued during the year	6.8	4.4
Balance at end of year	$ 13.6	$ 7.1

The Company classifies interest on tax uncertainties as interest expense. Net interest accrued for the year ended December 31, 2008 was $6.5 million. The Company did not accrue any penalties on uncertain tax positions.

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

Substantially all of the Company's unrecognized tax benefits impacting the effective tax rate are associated with the state income tax credits discussed in Note 3 under "Income Tax Matters." Settlement of this litigation could occur within the next 12 months, which would reduce the balance of the uncertain tax position by these amounts.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as "Long-term Debt." The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2008, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2008	2007
	(in millions)	
Capital lease	$ 5	$ 4
Senior notes	275	195
Total	$ 280	$ 199

Redemptions and/or maturities through 2013 applicable to total long-term debt are as follows: $280 million in 2009; $254 million in 2010; $414 million in 2011; $205 million in 2012; and $530 million in 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2008 was $1.9 billion. Proceeds from certain issuances are restricted until the expenditures are incurred.

Senior Notes

The Company issued $1.0 billion aggregate principal amount of unsecured senior notes in 2008. The proceeds of the issuance were used to repay a portion of the Company's short term indebtedness, fund note maturities, and fund the Company's continuous construction program. At December 31, 2008 and 2007, the Company had $4.8 billion and $4.0 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $68 million at December 31, 2008. Subsequent to December 31, 2008, the Company issued $500 million of Series 2009A 5.95% Senior Notes due February 2039. The proceeds from the sale of the Series 2009A Senior Notes were used by the Company to repay at maturity $150 million aggregate principal amount of the Company's Series U Floating Rate Senior Notes, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes.

Bank Term Loans

During 2008, the Company borrowed $300 million under a three-year term loan agreement and $100 million under a short-term loan agreement. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2008 and 2007, the Company had a capitalized lease obligation for its corporate headquarters building of $66 million and $69 million, respectively, with an interest rate of 8.0%. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities." At December 31, 2008 and 2007, the Company had capitalized lease obligations of $0.8 million and $1.9 million, respectively, for its vehicles. However, for ratemaking purposes, these obligations are treated as operating leases and, as such, lease payments are charged to expense as incurred. The annual expense incurred for these leases in 2008, 2007, and 2006 was $9.7 million, $9.2 million, and $9.6 million, respectively.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the Class A preferred stock and preference stock are subject to redemption at the option of the Company on or after a specified date (typically 5 or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

Dividend Restrictions

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

Bank Credit Arrangements

At December 31, 2008, the Company had credit arrangements with banks totaling $1.3 billion, of which $12 million was used to support outstanding letters of credit. Of these facilities, $225 million expire during 2009, with the remaining $1.1 billion expiring in 2012. $40 million of the facilities that expire in 2009 provides the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/8 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2008, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.3 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2008 was $636 million. In addition, the Company borrows under a commercial paper program. The amount of commercial paper outstanding at December 31, 2008, 2007, and 2006 was $256 million, $616 million, and $733 million, respectively. The Company also had $100 million of short-term bank loans outstanding at December 31, 2008. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

During 2008, the peak amount of short-term debt outstanding was $908 million and the average amount outstanding was $460 million. The average annual interest rate on short-term debt in 2008 was 2.9%.

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 manages a fuel-hedging program as discussed in Note 3 under "Retail Regulatory Matters – Fuel Hedging Program." The Company also enters into hedges of forward electricity sales. At December 31, 2008, the Company had a net $113 million fair value liability of energy-related derivative contracts designated as regulatory hedges in the financial statements. The gains and losses arising from these regulatory hedges are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. There was no material ineffectiveness related to energy related derivatives recorded in earnings for any period presented. The Company has energy-related hedges in place up to and including 2012.

The Company also enters into derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings for any period presented.

At December 31, 2008, the Company had $851 million notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains/(losses) as follows:

Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2008
(in millions)				*(in millions)*
Cash Flow Hedges on Existing Debt				
$ 301	SIFMA Index *	2.22%	December 2009	$ (3)
150	3-month LIBOR	2.63%	February 2009	-
300	1-month LIBOR	2.43%	April 2010	(5)
Cash Flow Hedges on Forecasted Debt				
100	3-month LIBOR	4.98%	February 2019	(21)

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

The fair value gains or losses for cash flow hedges are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. In 2008, 2007, and 2006, the Company settled gains/(losses) totaling approximately $(20) million, $12 million, and $(4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. The effective portion of these gains/(losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative. In 2008, the Company also settled an interest derivative early because of counterparty credit issues at a loss of approximately $(2) million. This loss is deferred in other comprehensive income and will be amortized into earnings once the forecasted debt is issued in 2009. Amounts reclassified from other comprehensive income to interest expense were immaterial for all periods presented. For 2009, pre-tax losses of approximately $(14) million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2019 and has deferred realized gains/(losses) that are being amortized through 2037.

Subsequent to December 31, 2008, the Company settled $100 million of hedges related to the forecasted debt issuance in February 2009 at a loss of approximately $16 million. This loss will be amortized into earnings over 10 years.

All derivative financials instruments are recognized as either assets or liabilities and are measured at fair value. See Note 10 for additional information.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $2.8 billion, $2.6 billion, and $2.6 billion in 2009, 2010, and 2011, respectively. This estimate assumes the Company's current request to include construction work in progress for Plant Vogtle Units 3 and 4 in rates is granted by regulators, beginning in 2011. If not, the estimate will increase by approximately $144 million in 2011. These amounts include $139 million, $114 million, and $105 million in 2009, 2010, and 2011, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included under "Fuel Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; 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. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

Long-Term Service Agreements

The Company has entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that

GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made quarterly based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $183 million over the remaining term of the agreement, which is currently projected to be approximately 10 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $9.8 million. The contract contains cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

The Company has entered into a LTSA with Mitsubishi Power Systems Americas, Inc. (MPS) for the purpose of providing certain parts and maintenance services for the three combined cycle units under construction at Plant McDonough, which are scheduled to go into service in February 2011, June 2011, and June 2012, respectively. The LTSA stipulates that MPS will perform all planned maintenance on each covered unit which includes the cost of all materials and services. MPS is also obligated to cover costs of unplanned maintenance on the gas turbines subject to limits specified in the LTSA. This LTSA will begin in 2011 and is in effect through two major inspection cycles per covered unit. Periodic payments to MPS are to be made quarterly and will also be made based on the scheduled inspections for the respective covered units. Payments to MPS under this agreement, which are subject to price escalation, are currently estimated to be $536.8 million for the term of the agreement which is expected to be between 12 and 13 years. However, the LTSA contains various termination provisions at the option of the Company.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.6 million tons, equating to approximately $111.7 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $10.3 million in 2009, $19.3 million in 2010, $14.9 million in 2011, $15.3 million in 2012, and $15.7 million in 2013.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008.

Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2009	$ 657	$2,497	$ 139
2010	349	2,001	114
2011	282	1,712	105
2012	364	671	108
2013	380	735	91
2014 and thereafter	2,917	1,999	33
Total	$4,949	$9,615	$ 590

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense were $77 million, $79 million, and $71 million for the years 2008, 2007, and 2006, respectively.

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

Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power from non-affiliates in the statements of income. Capacity payments totaled $48 million, $46 million, and $49 million in 2008, 2007, and 2006, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2008 were as follows:

	Vogtle Capacity Payments	Affiliated PPA	Non-Affiliated PPA
		(in millions)	
2009	$ 55	$ 220	$ 95
2010	54	153	136
2011	51	119	143
2012	46	107	116
2013	21	107	109
2014 and thereafter	114	596	1,476
Total	$ 341	$ 1,302	$ 2,075

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $52 million for 2008, $55 million for 2007, and $53 million for 2006.

At December 31, 2008, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2009	$ 33	$ 10	$ 43
2010	27	7	34
2011	25	6	31
2012	14	3	17
2013	12	3	15
2014 and thereafter	25	3	28
Total	$ 136	$ 32	$ 168

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $39.8 million. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

Guarantees

Alabama Power has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

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

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2008, there were 1,744 current and former employees of the Company participating in the stock option plan, and there were 33.2 million shares of Southern Company common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2008**	2007	2006
Expected volatility	13.1%	14.8%	16.9%
Expected term *(in years)*	5.0	5.0	5.0
Interest rate	2.8%	4.6%	4.6%
Dividend yield	4.5%	4.3%	4.4%
Weighted average grant-date fair value	$ 2.37	$ 4.12	$ 4.15

The Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2007	7,538,109	$30.59
Granted	1,430,140	35.78
Exercised	(961,426)	27.34
Cancelled	(14,387)	34.82
Outstanding at December 31, 2008	7,992,436	$31.90
Exercisable at December 31, 2008	5,308,585	$29.98

The number of stock options vested, and expected to vest in the future, as of December 31, 2008 was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. At December 31, 2008, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.2 years and 5.0 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $40.8 million and $37.3 million, respectively.

As of December 31, 2008, there was $1.5 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 10 months.

For the years ended December 31, 2008, 2007, and 2006, total compensation cost for stock option awards recognized in income was $4.2 million, $6.0 million, and $5.8 million, respectively, with the related tax benefit also recognized in income of $1.6 million, $2.3 million, and $2.0 million, respectively.

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

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $10.6 million, $17.4 million, and $10.3 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4.1 million, $6.7 million, and $4.0 million, respectively, for the years ended December 31, 2008, 2007, and 2006.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's Plants Hatch and Vogtle. The Act provides funds up to $12.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests, is $237 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $51 million.

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

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 4.7	$ -	$ 4.7
Nuclear decommissioning trusts[(a)]	260.3	198.8	-	459.1
Cash equivalents and restricted cash	146.9	-	-	146.9
Total fair value	$407.2	$203.5	$ -	$610.7
Liabilities:				
Energy-related derivatives	$ -	$117.9	$ -	$117.9
Interest rate derivatives	-	29.3	-	29.3
Total fair value	$ -	$147.2	$ -	$147.2

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Energy-related derivatives and interest rate derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The nuclear decommissioning trust funds are invested in a diversified mix of equity and fixed income securities. See Note 1 under "Nuclear Decommissioning" for additional information. The cash equivalents and restricted cash consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2008 and 2007 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2008	**$ 1,865**	**$ 325**	**$ 176**
June 2008	**2,111**	**442**	**248**
September 2008	**2,644**	**711**	**402**
December 2008	**1,792**	**182**	**77**
March 2007	$ 1,657	$ 279	$ 131
June 2007	1,844	361	188
September 2007	2,444	688	400
December 2007	1,627	189	117

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

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	2008	2007	2006	2005	2004
Operating Revenues (in thousands)	**$8,411,552**	$7,571,652	$7,245,644	$7,075,837	$5,727,768
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$902,927**	$836,136	$787,225	$744,373	$682,793
Cash Dividends on Common Stock (in thousands)	**$721,200**	$689,900	$630,000	$582,800	$588,700
Return on Average Common Equity (percent)	**13.56**	13.50	13.80	14.08	13.87
Total Assets (in thousands)	**$22,315,668**	$20,822,761	$19,308,730	$17,898,445	$16,598,778
Gross Property Additions (in thousands)	**$1,953,448**	$1,862,449	$1,276,889	$958,563	$1,252,197
Capitalization (in thousands):					
Common stock equity	**$6,879,243**	$6,435,420	$5,956,251	$5,452,083	$5,123,276
Preferred and preference stock	**265,957**	265,957	44,991	43,909	58,547
Long-term debt	**7,006,275**	5,937,792	5,211,912	5,365,323	4,916,694
Total (excluding amounts due within one year)	**$14,151,475**	$12,639,169	$11,213,154	$10,861,315	$10,098,517
Capitalization Ratios (percent):					
Common stock equity	**48.6**	50.9	53.1	50.2	50.7
Preferred and preference stock	**1.9**	2.1	0.4	0.4	0.6
Long-term debt	**49.5**	47.0	46.5	49.4	48.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred and 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	**2,039,503**	2,024,520	1,998,643	1,960,556	1,926,215
Commercial	**295,925**	295,478	294,654	289,009	283,507
Industrial	**8,248**	8,240	8,008	8,290	7,765
Other	**5,566**	4,807	4,371	4,143	4,015
Total	**2,349,242**	2,333,045	2,305,676	2,261,998	2,221,502
Employees (year-end)	**9,337**	9,270	9,278	9,273	9,294

N/A = Not Applicable.

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Residential	**$ 2,648,176**	$2,442,501	$2,326,190	$2,227,137	$1,900,961
Commercial	**2,917,270**	2,576,058	2,423,568	2,357,077	1,933,004
Industrial	**1,640,407**	1,403,852	1,382,213	1,406,295	1,217,536
Other	**80,492**	75,592	73,649	73,854	67,250
Total retail	**7,286,345**	6,498,003	6,205,620	6,064,363	5,118,751
Wholesale - non-affiliates	**568,797**	537,913	551,731	524,800	251,581
Wholesale - affiliates	**286,219**	277,832	252,556	275,525	172,375
Total revenues from sales of electricity	**8,141,361**	7,313,748	7,009,907	6,864,688	5,542,707
Other revenues	**270,191**	257,904	235,737	211,149	185,061
Total	**$8,411,552**	$7,571,652	$7,245,644	$7,075,837	$5,727,768
Kilowatt-Hour Sales (in thousands):					
Residential	**26,412,131**	26,840,275	26,206,170	25,508,472	24,829,833
Commercial	**33,058,109**	33,056,632	32,112,430	31,334,182	29,553,893
Industrial	**24,163,566**	25,490,035	25,577,006	25,832,265	27,197,843
Other	**670,588**	697,363	660,285	737,343	744,935
Total retail	**84,304,394**	86,084,305	84,555,891	83,412,262	82,326,504
Sales for resale - non-affiliates	**9,756,260**	10,577,969	10,685,456	10,588,891	5,429,911
Sales for resale - affiliates	**3,694,640**	5,191,903	5,463,463	5,033,165	4,925,744
Total	**97,755,294**	101,854,177	100,704,810	99,034,318	92,682,159
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.03**	9.10	8.88	8.73	7.66
Commercial	**8.82**	7.79	7.55	7.52	6.54
Industrial	**6.79**	5.51	5.40	5.44	4.48
Total retail	**8.64**	7.55	7.34	7.27	6.22
Wholesale	**6.36**	5.17	4.98	5.12	4.09
Total sales	**8.33**	7.18	6.96	6.93	5.98
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,969**	13,315	13,216	13,119	13,002
Residential Average Annual Revenue Per Customer	**$1,300**	$1,212	$1,173	$1,145	$995
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,995**	15,995	15,995	15,995	14,743
Maximum Peak-Hour Demand (megawatts):					
Winter	**14,221**	13,817	13,528	14,360	13,087
Summer	**17,270**	17,974	17,159	16,925	16,129
Annual Load Factor (percent)	**58.4**	57.5	61.8	59.4	61.0
Plant Availability (percent):					
Fossil-steam	**90.95**	90.8	91.4	90.0	87.1
Nuclear	**89.81**	92.4	90.7	89.3	94.8
Source of Energy Supply (percent):					
Coal	**58.7**	61.5	59.0	60.7	57.6
Nuclear	**14.8**	14.6	14.4	14.5	16.5
Hydro	**0.6**	0.5	0.9	1.9	1.5
Oil and gas	**5.1**	5.5	5.0	3.0	0.2
Purchased power -					
From non-affiliates	**5.1**	3.8	3.8	4.6	6.0
From affiliates	**15.7**	14.1	16.9	15.3	18.2
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
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Directors

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

Ronald D. Brown (Deceased 4/28/2008)
President and Chief Executive Officer
Atlanta Life Financial Group

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

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

Stephen S. Green (Elected effective 8/20/2008)
President and Chief Executive Officer
Stephen Green Properties, Inc.

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

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

Beverly Daniel Tatum (Elected effective 8/20/2008)
President
Spelman College

D. Gary Thompson
Retired (12/2004)
(Wachovia Corporation)

Richard W. Ussery
Retired (7/2006)
(Total System Services, Inc.)

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

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

Officers

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

Mickey A. Brown
Executive Vice President
Customer Service Organization

Ronnie R. Labrato (Elected effective 3/31/09)
Executive Vice President, Chief Financial Officer and Treasurer

Cliff S. Thrasher (Retired effective 3/31/09)
Executive Vice President, Chief Financial Officer and Treasurer

Chris C. Womack (Resigned effective 12/31/08)
Executive Vice President
External Affairs

Judy M. Anderson (Retired effective 3/31/09)
Senior Vice President
Charitable Giving

W. Craig Barrs (Elected effective 1/1/09)
Senior Vice President
External Affairs

Thomas P. Bishop (Elected effective 9/20/08)
Senior Vice President and General Counsel
Georgia Power Company

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President
Customer Service and Sales

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

James H. Miller III (Resigned effective 8/27/08)
Senior Vice President and General Counsel

DIRECTORS AND OFFICERS
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Michael K. Anderson
Vice President
Corporate Services

Robert A. Bell (Retirement effective 4/1/08)
Vice President
Human Resources

Rebecca A. Blalock
Vice President
Information Resources

P. Mike Clanton
Vice President
Customer Service

Ann P. Daiss
Vice President, Comptroller and Chief Accounting Officer

Walter Dukes
Vice President
East Region

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Vice President
Governmental and Regulatory Affairs

Oscar C. Harper IV
Vice President
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

Cathy P. Hill (Elected effective 4/19/2008)
Vice President
Coastal Region

Charles H. Huling
Vice President
Environmental Affairs

Marsha S. Johnson (Elected effective 4/1/08)
Vice President
Human Resources

Anne H. Kaiser
Vice President
Northwest Region

Jacki W. Lowe
Vice President
West Region

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Vice President
South Region

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

Leslie R. Sibert
Vice President
Transmission

James E. Sykes, Jr.
Vice President
Northeast Region

Mark K. Tate
Assistant Comptroller

Thomas J. Wicker
Vice President
Central Region

Anthony L. Wilson
Vice President
Distribution

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.3 million customers within its service area. In 2008, retail energy sales accounted for 86 percent of the Company's total sales of 97.8 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries.

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

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

6.50% Series 2007A Preference Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

There is no market for the Company's common stock, all of which is owned by Southern Company.

Dividends on the Company's common stock are payable at the discretion of the Company's board of directors. The dividends declared by the Company to its common stockholder for the past two years were as follows:

Quarter	2008	2007
First	$180,300	$172,475
Second	180,300	172,475
Third	180,300	172,475
Fourth	180,300	172,475

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

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (404) 506-7450.

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

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

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