GEORGIA POWER COMPANY

2011 Annual Report

GEORGIA POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Georgia Power Company 2011 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, 2011.

W. Paul Bowers
President and Chief Executive Officer

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer

February 24, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
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 The Southern Company) as of December 31, 2011 and 2010, 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, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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 32 to 80) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 24, 2012

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 and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. The Company is currently constructing two new nuclear and two new combined cycle generating units. A third combined cycle generating unit went into commercial operation on December 28, 2011. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. In December 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including a base rate increase of approximately $562 million effective January 1, 2011, and additional increases in 2012 and 2013.

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 performance 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 2011 fossil/hydro Peak Season EFOR of 1.55% was 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 2011 performance was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2011 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR – fossil/hydro	4.80% or less	1.55%
Net Income After Dividends on Preferred and Preference Stock	$1.1 billion	$1.1 billion

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 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 2011 net income after dividends on preferred and preference stock totaled $1.1 billion representing a $195 million, or 20.5%, increase over the previous year. The increase was due primarily to increases in retail base revenues, effective January 1, 2011, as authorized under the 2010 ARP and the financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4), collected through the Nuclear Construction Cost Recovery (NCCR) tariff, partially offset by closer to normal weather in 2011 compared to 2010, higher non-fuel operating expenses, lower allowance for funds used during construction (AFUDC) equity, and higher income taxes. The increase was also due to a reduction in interest expense arising from the settlement of tax litigation with the Georgia Department of Revenue (DOR), partially offset by a decrease in the amortization of the regulatory liability related to other cost of removal obligations.

The Company's 2010 net income after dividends on preferred and preference stock totaled $950 million representing a $136 million, or 16.7%, increase over the previous year. The increase was due primarily to higher residential base revenues resulting from colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 and increased amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC, partially offset by increases in operations and maintenance expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$ 8,800**	**$ 451**	$ 657
Fuel	**2,789**	**(313)**	385
Purchased power	**1,103**	**157**	(33)
Other operations and maintenance	**1,777**	**43**	240
Depreciation and amortization	**715**	**157**	(97)
Taxes other than income taxes	**369**	**25**	27
Total operating expenses	**6,753**	**69**	522
Operating income	**2,047**	**382**	135
Allowance for equity funds used during construction	**96**	**(51)**	50
Interest expense, net of amounts capitalized	**(343)**	**32**	11
Other income (expense), net	**(13)**	**4**	(17)
Income taxes	**625**	**172**	43
Net income	**1,162**	**195**	136
Dividends on preferred and preference stock	**17**	**-**	-
Net income after dividends on preferred and preference stock	**$ 1,145**	**$ 195**	$ 136

Operating Revenues

Details of operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail – prior year	**$ 7,608**	$ 6,912
Estimated change in –		
Rates and pricing	**703**	-
Sales growth (decline)	**(9)**	48
Weather	**(105)**	207
Fuel cost recovery	**(98)**	441
Retail – current year	**8,099**	7,608
Wholesale revenues –		
Non-affiliates	**341**	380
Affiliates	**32**	53
Total wholesale revenues	**373**	433
Other operating revenues	**328**	308
Total operating revenues	**$ 8,800**	$ 8,349
Percent change	**5.4%**	8.5%

Retail base revenues of $4.8 billion in 2011 increased by $588 million, or 14.0%, from 2010 primarily due to increases authorized under the 2010 ARP, which became effective January 1, 2011. This increase was partially offset by closer to normal weather in 2011 compared to 2010. The increase in base revenues also includes the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Funds Used During Construction Equity" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Residential base revenues increased $225 million, or 11.8%, commercial base revenues increased $236 million, or 14.1%, and industrial base revenues increased $118 million, or 21.4%.

Retail base revenues of $4.2 billion in 2010 increased by $255 million, or 6.5%, from 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009. Residential base revenues increased $187 million, or 10.9%, commercial base revenues increased $50 million, or 3.1%, and industrial base revenues increased $17 million, or 3.1%. Revenues from changes in rates and pricing in 2010 were flat as the increased recognition of environmental compliance cost recovery (ECCR) revenues in accordance with the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan) was offset by pricing reductions from the structure of the Company's traditional base rate tariffs.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) 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:

	2011	2010	2009
		(in millions)	
Other power sales –			
Capacity and other	**$ 177**	$ 155	$ 140
Energy	**164**	194	186
Total	**341**	349	326
Unit power sales –			
Capacity	**-**	18	43
Energy	**-**	13	26
Total	**-**	31	69
Total non-affiliated	**$ 341**	$ 380	$ 395

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales, and from a unit power sales agreement which has now expired. Wholesale revenues from PPAs and unit power sales agreements have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Revenues from other non-affiliated sales decreased $8 million, or 2.3%, in 2011 and increased $23 million, or 7.1%, in 2010. The decrease in 2011 was primarily due to a 16.3% decrease in kilowatt-hour (KWH) sales from lower demand resulting from closer to normal weather in 2011 compared to 2010 and the lower market costs of available energy compared to Company-owned generation. The increase in 2010 was primarily due to higher fuel costs and revenues from a PPA that replaced the unit power sales agreement that expired in May 2010.

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 2011 and 2010, wholesale revenues from sales to affiliates decreased $21 million and $59 million from the prior year, respectively, due to decreases of 37.4% and 60.1%, respectively, in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of Company-owned generation. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $20 million, or 6.5%, in 2011 from the prior year primarily due to new contracts that replaced the transmission component of a unit power sales agreement that expired in May 2010 and increased usage of the Company's transmission system by non-affiliate companies. Other operating revenues increased $35 million, or 12.8%, in 2010 from the prior year primarily due to a $25 million increase in transmission revenues related to increased usage of the Company's transmission system by non-affiliated companies, an increase of $4 million in outdoor lighting revenues primarily as a result of new customer sales associated with government stimulus programs, and an increase of $6 million in late payment fees and customer maintenance request revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in billions)				
Residential	**27.2**	**(7.5)%**	12.0%	**(0.4)%**	0.9%
Commercial	**32.9**	**(2.8)**	3.9	**(0.4)**	(0.4)
Industrial	**23.5**	**1.3**	6.4	**1.6**	5.1
Other	**0.7**	**(0.9)**	(1.2)	**(0.6)**	(1.9)
Total retail	**84.3**	**(3.3)**	7.1	**0.2%**	1.5%
Wholesale					
Non-affiliates	**3.9**	**(16.3)**	(10.5)		
Affiliates	**0.6**	**(37.4)**	(60.1)		
Total wholesale	**4.5**	**(20.0)**	(26.6)		
Total energy sales	**88.8**	**(4.3)%**	4.2%		

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

In 2011, residential and commercial KWH sales decreased compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Industrial KWH sales increased in 2011 compared to 2010 primarily due to increased demand in the primary metals sector.

In 2010, residential, commercial, and industrial KWH sales increased compared to 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009 and a slowly improving economy.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

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:

	2011	2010	2009
Total generation *(billions of KWHs)*	**65.5**	75.3	72.4
Total purchased power *(billions of KWHs)*	**26.8**	21.7	20.4
Sources of generation *(percent)* -			
Coal	**62**	67	67
Nuclear	**23**	21	21
Gas	**13**	10	10
Hydro	**2**	2	2
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.70**	4.53	4.12
Nuclear	**0.78**	0.66	0.55
Gas	**4.92**	5.75	5.30
Average cost of fuel, generated *(cents per net KWH)*	**3.80**	3.82	3.48
Average cost of purchased power *(cents per net KWH)* *	**5.38**	5.64	6.06

*Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $3.9 billion in 2011, a decrease of $156 million, or 3.9%, compared to 2010. This decrease was primarily due to an $86 million decrease in the average cost of purchased power and gas, partially offset by increases in the average cost of coal and nuclear fuel. The decrease was also due to a $358 million decrease related to fewer KWHs generated as a result of lower customer demand, partially offset by a $288 million increase in KWHs purchased as the market cost of energy was lower than Company-owned generation.

Fuel and purchased power expenses were $4.0 billion in 2010, an increase of $352 million, or 9.5%, compared to 2009. This increase was due to a $160 million increase in the average cost of fossil and nuclear fuel and a $192 million increase related to more KWHs generated primarily due to higher customer demand as a result of colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011. In early 2011, uranium prices continued the steady increase started during the second half of 2010. In March 2011, uranium prices fell sharply from the highs earlier in the year. After some price volatility in the second quarter 2011, the price leveled and remained relatively constant for the remainder of 2011. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2011; however, 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 2011, other operations and maintenance expenses increased $43 million, or 2.5%, compared to 2010. The increase was due to a $22 million increase in customer assistance expenses related to new demand side management programs in 2011, an $8 million increase in uncollectible account expense as a result of higher revenues and current economic conditions, and a $6 million increase in workers compensation expense resulting from a higher volume of claims.

In 2010, other operations and maintenance expenses increased $240 million, or 16.1%, compared to 2009. The increase was primarily due to increases of $142 million in power generation, $74 million in transmission and distribution, and $25 million in customer accounting, service, and sales due to cost containment efforts in 2009 as a result of economic conditions. The increase in power generation operations and maintenance expenses was also due to higher generation levels to meet increased customer demand in 2010.

Depreciation and Amortization

Depreciation and amortization increased $157 million, or 28.1%, in 2011 compared to 2010. This increase was primarily due to a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein, Note 1 to the financial statements under "Depreciation and Amortization," and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Depreciation and amortization decreased $97 million, or 14.8%, in 2010 compared to the prior year. This decrease was primarily due to a $133 million increase in amortization of the regulatory liability related to other cost of removal obligations, as authorized by the Georgia PSC, partially offset by increased depreciation related to additional plant in service related to transmission, distribution, and environmental projects.

Taxes Other Than Income Taxes

In 2011, taxes other than income taxes increased $25 million, or 7.3%, from the prior year primarily due to a $17 million increase in property taxes and a $9 million increase in municipal franchise fees related to retail revenues. In 2010, taxes other than income taxes increased $27 million, or 8.5%, from the prior year primarily due to municipal franchise fees resulting from retail revenues during 2010.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $51 million, or 34.7%, in 2011 compared to the prior year primarily due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized with an offsetting increase in operating revenues through the NCCR tariff. AFUDC equity increased $50 million, or 51.5%, in 2010 compared to the prior year primarily due to the increase in construction related to three new combined cycle units at Plant McDonough, Plant Vogtle Units 3 and 4, and ongoing environmental and transmission projects. See FUTURE EARNINGS POTENTIAL – "Construction" herein and Note 3 to the financial statements under "Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2011, interest expense, net of amounts capitalized decreased $32 million, or 8.5%, from the prior year primarily due to a reduction of $23 million in interest expense related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds, partially offset by a reduction in AFUDC debt due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base. See Note 3 to the financial statements under "Income Tax Matters" for additional information on the Georgia DOR settlement. In 2010, interest expense, net of amounts capitalized decreased $11 million, or 2.8%, from the prior year primarily due to a $14 million increase in interest capitalized compared to the prior year as a result of increased construction activity.

Other Income (Expense), Net

The 2011 increase in other income (expense), net compared to the prior year was immaterial. Other income (expense), net decreased $17 million in 2010 compared to the prior year primarily as a result of a $9 million decrease in wholesale operating fees and increased donations of $5 million.

Income Taxes

Income taxes increased $172 million, or 38.0%, in 2011 compared to the prior year primarily due to higher pre-tax earnings, a decrease in non-taxable AFUDC equity, and the recognition in 2010 of certain state income tax credits. Income taxes increased $43 million, or 10.5%, in 2010 compared to the prior year primarily due to higher pre-tax earnings, partially offset by increases in non-taxable AFUDC equity and state income tax credits.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

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 wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state 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 differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's ECCR tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 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. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power Company (Alabama Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations 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, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit 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 allege 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 some of the defendants (including Southern Company) 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. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. 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 2011, the Company had invested approximately $3.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $101 million, $217 million, and $440 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $714 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$237	$249	$228

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $237 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $5 billion to $7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $237 million that is also included in the 2012 through 2013 base level capital investment of the Company described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $320 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $640 million over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	-	Up to $70	Up to $250
Proposed water and coal combustion byproducts rules	Up to $30	Up to $160	Up to $450
Total potential incremental environmental compliance investments	**Up to $30**	**Up to $230**	**Up to $700**

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information.

As of December 31, 2011, the Company had total generating capacity of approximately 16,588 megawatts (MWs), of which 9,124 MWs are coal-fired. Over the past several years, the Company has installed various pollution control technologies on its coal-fired units, including both selective catalytic reduction equipment and scrubbers on its eight largest coal units making up 5,200 MWs of the Company's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, jointly owned with Alabama Power, is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to the Company and Alabama Power through a PPA. The impact of SEGCO's compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could 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. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $3.5 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 planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Company's service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Company's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid-2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Company's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the State of Georgia.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

On March 21, 2011, the EPA published the final Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) rule establishing emissions limits for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. At the same time, the EPA issued a notice of intent to reconsider the final rule and, on May 16, 2011, the EPA issued an administrative stay to prevent the rule from becoming effective. On December 2, 2011, the EPA proposed a reconsideration rule to change certain aspects of the final rule. On January 9, 2012, however, the U.S. District Court for the District of Columbia Circuit vacated the EPA's administrative stay. Although the U.S. District Court for the District of Columbia Circuit's decision would allow the original IB MACT rule to become effective, the EPA has indicated that it will not implement the rule until the EPA's proposed revisions can be finalized. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time. On October 18, 2011, the Georgia PSC approved the Company's request to further delay the decision to convert Plant Mitchell Unit 3 from coal to biomass for two to four years, until there is greater clarity regarding the IB MACT rule and other proposed and recently adopted regulations.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, the MATS rule, and the IB MACT rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2011, the Company had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. As a result of uncertainties related to the potential federal air quality regulations described above, the Company has suspended certain work related to the installation of emissions control equipment at Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7. The Company continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. The Company may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described previously, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates 11 electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Georgia and Alabama each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described previously, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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. 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 Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 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, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 58 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 45 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company is actively constructing new generating facilities with lower greenhouse gas emissions. These include Plant Vogtle Units 3 and 4 and two additional combined cycle units at Plant McDonough. The Company has also proposed the conversion of Plant Mitchell from coal-fired to biomass generation and is currently evaluating the costs and viability of other renewable technologies for the State of Georgia.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff (Advocacy Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been or will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Construction – Other Construction" herein for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

2011 Integrated Resource Plan Update

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the 2010 ARP.

On August 4, 2011, the Company filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included the Company's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. The Company also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, the Company is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 MWs of capacity. The Company is currently updating its economic analysis of these units based on the final MATS rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, the Company cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes the Company's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process.

In addition, the Company filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, the Company entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on the Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in the Company's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

The Company's under recovered fuel balance totaled approximately $137 million at December 31, 2011, all of which is included in current assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2011, the balance in the regulatory asset related to storm damage was $43 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company also filed similar claims for the years 2002 through 2004. In 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, the Company and the Georgia DOR agreed to a settlement resolving the claims. As a result, the Company recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, the Company recorded a reduction of approximately $23 million in related interest expense. See "Construction – Other Construction" herein and Note 3 under "Retail Regulatory Matters – Construction – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information on this regulatory liability.

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Consequently, it is estimated there will be a positive cash flow benefit of between $325 million and $400 million in 2012.

Construction

Nuclear

In 2009, the Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization to Southern Nuclear Operating Company (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), related to Plant Vogtle Units 3 and 4. See Note 4 to the financial statements for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows 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. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved the Company's NCCR tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. The Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, the Company's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve the Company's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse 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 MWs 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 agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. 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 is 45.7%.

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 Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse 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 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 COLs 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.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and the Company (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and the Company expects the Consortium to seek recovery of these costs. The Company is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. The Company has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and the Company intends to vigorously defend itself in these matters. The Company expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, the Company would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and the Company (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

The Company is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. The Company completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between the Company and the Georgia PSC Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "PSC Matters – Rate Plans" herein for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. 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 air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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 or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). 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 accounting standards which require 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 the accounting standards 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 and financial condition 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 GAAP. 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 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 GAAP, 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.

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, 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.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $9 million or less change in total benefit expense and a $122 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. 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. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company funded approximately $4 million to its nuclear decommissioning trust funds in 2011 and expects to fund approximately $2 million in 2012 and 2013.

Net cash provided from operating activities totaled $2.6 billion in 2011, an increase of $785 million from 2010, primarily due to higher retail operating revenues, increased deferred income taxes in 2011 primarily due to bonus depreciation, and contributions to the qualified pension plan in 2010. Net cash provided from operating activities totaled $1.8 billion in 2010, an increase of $429 million from 2009, primarily due to a $136 million increase in net income, fuel inventory reductions in 2010 compared to additions in 2009, and a net increase of $94 million in deferred and prepaid income taxes primarily due to the extension of bonus depreciation and the change in the tax accounting method for repair costs (See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – and "Bonus Depreciation" herein), partially offset by contributions to the qualified pension plan.

Net cash used for investing activities totaled $1.8 billion, $2.2 billion, and $2.4 billion in 2011, 2010, and 2009, 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 has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash (used for)/provided from financing activities totaled $(836) million, $391 million, and $881 million for 2011, 2010, and 2009, respectively. The decrease in 2011 compared to 2010 was primarily a reflection of lower capital contributions from Southern Company and higher common stock dividends paid to Southern Company and lower debt issuances due to the availability of more internally generated cash in 2011. The decrease in 2010 when compared to 2009 was primarily related to additional issuances of senior notes and an increase in notes payable, partially offset by an increase in the redemption of senior notes. The statements of cash flows provide additional details. See "Financing Activities" herein for additional information.

Significant balance sheet changes in 2011 include a $1.2 billion increase in property, plant, and equipment related to the construction activities discussed above, a $670 million increase in accumulated deferred income taxes primarily related to bonus depreciation, and a $231 million increase in paid in capital reflecting equity contributions from Southern Company.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.4% in 2011 and 48.8% in 2010. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential U.S. Department of Energy (DOE) loan guarantees, 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, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In June 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for the Company. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein and Note 3 to the financial statements under "Construction – Nuclear" for more information on Plant Vogtle Units 3 and 4.

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 (1933 Act). The amounts of securities authorized by the Georgia PSC and the FERC, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

At December 31, 2011, the Company had approximately $13 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires[(a)]			
2014	**2016**	**Total**	**Unused**
(in millions)			
$250	$1,500	$1,750	$1,745

(a) No credit arrangements expire in 2012, 2013, or 2015.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2011, the Company had $868 million outstanding variable rate pollution control revenue bonds requiring liquidity support.

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. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings, excluding $2 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	**Weighted Average Interest Rate**	**Average Outstanding**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding**
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$ 313	0.20%	$ 208	0.26%	$ 681
Short-term bank debt	200	1.18%	9	1.18%	200
Total	$ 513	0.51%	$ 217	0.33%	
December 31, 2010:					
Commercial paper	$ 575	0.30%	$ 167	0.25%	$ 575

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

Pollution Control Revenue Bonds

In December 2010, the Development Authority of Floyd County issued $53 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2010 for the benefit of the Company. These bonds were purchased and held by the Company as of December 31, 2010. In January 2011, the Company remarketed these bonds to investors in a variable interest rate mode.

In January 2011, the Company purchased and held $83.5 million of pollution control revenue bonds. The Company remarketed these bonds to investors in January 2011. In addition, in April 2011, the Company purchased and held $113.5 million of pollution control revenue bonds. The Company remarketed these bonds to investors in June 2011.

In July 2011, the Company redeemed $67 million of the Development Authority of Appling County Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), First Series 2006. In September 2011, the Development Authority of Appling County issued $67 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), First Series 2011 due September 1, 2041 for the benefit of the Company. The bonds were issued in a variable interest rate mode.

In July 2011, approximately $8 million of Development Authority of Cobb County Pollution Control Revenue Bonds (Georgia Power Company Plant McDonough Project), First Series 1991 matured.

In September 2011, the Company remarketed $173 million aggregate principal amount of the Development Authority of Bartow County Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $114.3 million aggregate principal amount of the Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2009 to investors in a variable interest rate mode. The Company had purchased and was holding the bonds as of December 31, 2010.

In September 2011, the Company redeemed approximately $14.1 million aggregate principal amount of Development Authority of Coweta County Pollution Control Revenue Bonds (Georgia Power Company Plant Yates Project), Second Series 2001.

In November 2011, the Company redeemed $53 million aggregate principal amount of the Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 1999.

Senior Notes and Trust Preferred Securities

In January 2011, the Company's $100 million aggregate principal amount of Series S 4.00% Senior Notes due January 15, 2011 matured.

In January 2011, the Company issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

In April 2011, the Company issued $250 million aggregate principal amount of Series 2011B 3.00% Senior Notes due April 15, 2016. The proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

In September 2011, the Company redeemed (i) $140.7 million aggregate principal amount of Series M 5.40% Senior Insured Notes due March 1, 2033, (ii) $35 million aggregate principal amount of Savannah Electric Series F 5.50% Senior Notes due December 12, 2028, and (iii) $200 million aggregate principal amount of Series G 5-7/8% Junior Subordinated Notes due January 15, 2044 and the related Trust Preferred Securities of Georgia Power Capital Trust VII (as well as approximately $6.2 million of such Series G Junior Subordinated Notes related to the Company's ownership of the common securities of Georgia Power Capital Trust VII).

In December 2011, the Company redeemed $150 million aggregate principal amount of Series 2006A 5.65% Senior Insured Quarterly Notes due December 15, 2040.

Other

In March 2011, the Company's $300 million variable rate bank term loan due on March 4, 2011 matured and was partially replaced by two one-year $125 million aggregate principal amount variable rate bank loans that bear interest based on one-month London Interbank Offered Rate (LIBOR).

In December 2011, the Company entered into three six-month floating rate bank loans bearing interest based on one-month LIBOR. These short-term loans were for $75 million, $75 million, and $50 million aggregate principal amounts, and proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company entered into a floating rate six-month short-term bank loan in an aggregate amount of $100 million, bearing interest based on one-month LIBOR. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

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.

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, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 68
Below BBB- and/or Baa3	1,534

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system 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 and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. 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 testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $2.0 billion of outstanding variable rate long-term debt and short-term bank loans, at January 1, 2012 was 0.56%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $20 million at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company continues to manage a fuel hedging program implemented per the guidelines of the Georgia PSC.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (100)**	$ (75)
Contracts realized or settled	**92**	85
Current period changes[a]	**(74)**	(110)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (82)**	$ (100)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was an increase of $18 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 73.3 million mmBtu with a weighted average swap contract cost approximately $1.65 per mmBtu above market prices, and at December 31, 2010 had a net hedge volume of 58.7 million mmBtu with a weighted average swap contract cost approximately $1.74 per mmBtu above market prices. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program, which has a 48-month time horizon. Therefore, 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 and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ -	$ -	$ -
Level 2	(82)	(60)	(22)
Level 3	-	-	-
Fair value of contracts outstanding at end of period	$ (82)	$ (60)	$ (22)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., 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 Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs to the Company for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from \$5 billion to \$7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. Included in this amount is \$237 million that is also included in the 2012 through 2013 base level capital investment of the Company, described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	\$2,066	\$ 2,121	\$ 1,887
Existing environmental statutes and regulations	237	249	228
Total construction program base level capital investment	**\$2,303**	**\$ 2,370**	**\$ 2,115**
Potential incremental environmental compliance investments:			
MATS rule	-	Up to \$70	Up to\$250
Proposed water and coal combustion byproducts rules	Up to \$30	Up to \$160	Up to \$450
Total potential incremental environmental compliance investments	**Up to \$30**	**Up to \$230**	**Up to \$700**

The construction program is 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; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, 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; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 and Note 7 to the financial statements under "Construction – Nuclear" and "Construction Program," respectively, for additional information.

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, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 450	$ 1,675	$ 504	$ 5,805	$ -	$ 8,434
Interest	340	613	555	4,640	-	6,148
Preferred and preference stock dividends[b]	17	35	35	-	-	87
Energy-related derivative obligations[c]	68	27	-	-	-	95
Operating leases	34	52	25	8	-	119
Capital leases	5	10	12	28	-	55
Unrecognized tax benefits and interest[d]	17	-	-	-	36	53
Purchase commitments[e] –						
Capital[f]	2,054	4,030	-	-	-	6,084
Limestone [g]	18	36	13	8	-	75
Coal	1,473	1,615	461	238	-	3,787
Nuclear fuel	257	330	173	528	-	1,288
Natural gas[h]	546	1,148	826	2,179	-	4,699
Purchased power[i]	262	484	488	1,846	-	3,080
Long-term service agreements[j]	22	102	109	472	-	705
Trusts –						
Nuclear decommissioning[k]	2	3	3	34	-	42
Pension and other postretirement benefit plans[l]	37	68	-	-	-	105
Total	$ 5,602	$ 10,228	$ 3,204	$ 15,786	$ 36	$ 34,856

(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, 2012, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $36 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 under "Unrecognized Tax Benefits" 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 2011, 2010, and 2009 were $1.8 billion, $1.7 billion, and $1.5 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $30 million, up to $230 million, and up to $700 million for 2012, 2013, and 2014, respectively. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization 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, 2011.

(i) Excludes four PPAs that are subject to certification by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – 2011 Integrated Resource Plan Update" to the financial statements for additional information.

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

(k) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP.

(l) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, the Company's projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, start and 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 changes, 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, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, the pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- 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 and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- 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 wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- 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 influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2011, 2010, and 2009

Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 8,099**	$ 7,608	$ 6,912
Wholesale revenues, non-affiliates	**341**	380	395
Wholesale revenues, affiliates	**32**	53	112
Other revenues	**328**	308	273
Total operating revenues	**8,800**	8,349	7,692
Operating Expenses:			
Fuel	**2,789**	3,102	2,717
Purchased power, non-affiliates	**390**	368	269
Purchased power, affiliates	**713**	578	710
Other operations and maintenance	**1,777**	1,734	1,494
Depreciation and amortization	**715**	558	655
Taxes other than income taxes	**369**	344	317
Total operating expenses	**6,753**	6,684	6,162
Operating Income	**2,047**	1,665	1,530
Other Income and (Expense):			
Allowance for equity funds used during construction	**96**	147	97
Interest expense, net of amounts capitalized	**(343)**	(375)	(386)
Other income (expense), net	**(13)**	(17)	-
Total other income and (expense)	**(260)**	(245)	(289)
Earnings Before Income Taxes	**1,787**	1,420	1,241
Income taxes	**625**	453	410
Net Income	**1,162**	967	831
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,145**	$ 950	$ 814

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2011, 2010, and 2009

Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$1,145**	$950	$814
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of \$-, \$-, and \$(1), respectively	**-**	-	(2)
Reclassification adjustment for amounts included in net income, net of tax of \$2, \$6, and \$9, respectively	**2**	10	14
Total other comprehensive income (loss)	**2**	10	12
Comprehensive Income	**$1,147**	$960	$826

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Net income	**$ 1,162**	$ 967	$ 831
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**867**	724	791
Deferred income taxes	**500**	342	191
Deferred revenues	**(1)**	(101)	(49)
Allowance for equity funds used during construction	**(96)**	(147)	(97)
Pension and postretirement funding	**(15)**	(195)	(22)
Other, net	**(36)**	29	23
Changes in certain current assets and liabilities --			
-Receivables	**235**	168	127
-Fossil fuel stock	**(99)**	103	(242)
-Prepaid income taxes	**72**	(36)	21
-Other current assets	**(21)**	(9)	(7)
-Accounts payable	**44**	(99)	(54)
-Accrued taxes	**(36)**	31	(19)
-Accrued compensation	**7**	62	(101)
-Other current liabilities	**49**	8	25
Net cash provided from operating activities	**2,632**	1,847	1,418
Investing Activities:			
Property additions	**(1,861)**	(2,190)	(2,515)
Nuclear decommissioning trust fund purchases	**(1,845)**	(1,772)	(989)
Nuclear decommissioning trust fund sales	**1,841**	1,768	984
Cost of removal, net of salvage	**(42)**	(67)	(56)
Change in construction payables, net of joint owner portion	**123**	36	106
Other investing activities	**(7)**	(19)	52
Net cash used for investing activities	**(1,791)**	(2,244)	(2,418)
Financing Activities:			
Increase (decrease) in notes payable, net	**(61)**	252	(33)
Proceeds --			
Capital contributions from parent company	**214**	688	931
Pollution control revenue bonds issuances and remarketings	**604**	-	417
Senior notes issuances	**550**	1,950	1,000
Other long-term debt issuances	**250**	-	1
Redemptions and repurchases --			
Pollution control revenue bonds	**(339)**	(516)	(327)
Senior notes	**(427)**	(1,112)	(333)
Other long-term debt	**(303)**	-	-
Long-term debt to affiliate trust	**(206)**	-	-
Payment of preferred and preference stock dividends	**(17)**	(18)	(18)
Payment of common stock dividends	**(1,096)**	(820)	(739)
Other financing activities	**(5)**	(33)	(18)
Net cash provided from (used for) financing activities	**(836)**	391	881
Net Change in Cash and Cash Equivalents	**5**	(6)	(119)
Cash and Cash Equivalents at Beginning of Year	**8**	14	133
Cash and Cash Equivalents at End of Year	**$ 13**	$ 8	$ 14
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $37, $54 and $40 capitalized, respectively)	**$346**	$339	$341
Income taxes (net of refunds)	**54**	149	228
Noncash transactions - accrued property additions at year-end	**391**	310	243

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

BALANCE SHEETS
At December 31, 2011 and 2010
Georgia Power Company 2011 Annual Report

Assets	**2011**	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 13**	$ 8
Receivables --		
Customer accounts receivable	**571**	580
Unbilled revenues	**172**	172
Under recovered regulatory clause revenues	**137**	184
Joint owner accounts receivable	**87**	60
Other accounts and notes receivable	**61**	67
Affiliated companies	**26**	21
Accumulated provision for uncollectible accounts	**(13)**	(11)
Fossil fuel stock, at average cost	**723**	624
Materials and supplies, at average cost	**406**	371
Vacation pay	**82**	78
Prepaid income taxes	**71**	99
Other regulatory assets, current	**108**	105
Other current assets	**106**	80
Total current assets	**2,550**	2,438
Property, Plant, and Equipment:		
In service	**27,804**	26,397
Less accumulated provision for depreciation	**10,296**	9,966
Plant in service, net of depreciation	**17,508**	16,431
Other utility plant, net	**55**	-
Nuclear fuel, at amortized cost	**443**	386
Construction work in progress	**3,274**	3,287
Total property, plant, and equipment	**21,280**	20,104
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**63**	70
Nuclear decommissioning trusts, at fair value	**667**	818
Miscellaneous property and investments	**44**	42
Total other property and investments	**774**	930
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**756**	723
Prepaid pension costs	**-**	91
Deferred under recovered regulatory clause revenues	**-**	214
Other regulatory assets, deferred	**1,604**	1,207
Other deferred charges and assets	**187**	207
Total deferred charges and other assets	**2,547**	2,442
Total Assets	**$27,151**	$25,914

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

BALANCE SHEETS

At December 31, 2011 and 2010

Georgia Power Company 2011 Annual Report

Liabilities and Stockholder's Equity	2011	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 455**	$ 415
Notes payable	**515**	576
Accounts payable --		
Affiliated	**337**	243
Other	**686**	574
Customer deposits	**213**	198
Accrued taxes --		
Accrued income taxes	**36**	1
Unrecognized tax benefits	**14**	187
Other accrued taxes	**304**	328
Accrued interest	**92**	94
Accrued vacation pay	**60**	58
Accrued compensation	**125**	109
Liabilities from risk management activities	**68**	77
Other regulatory liabilities, current	**65**	31
Nuclear decommissioning trust securities lending collateral	**32**	144
Other current liabilities	**139**	134
Total current liabilities	**3,141**	3,169
Long-Term Debt (See accompanying statements)	**8,018**	7,931
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,388**	3,718
Deferred credits related to income taxes	**122**	129
Accumulated deferred investment tax credits	**220**	229
Employee benefit obligations	**905**	684
Asset retirement obligations	**734**	705
Other cost of removal obligations	**110**	131
Other deferred credits and liabilities	**224**	211
Total deferred credits and other liabilities	**6,703**	5,807
Total Liabilities	**17,862**	16,907
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**9,023**	8,741
Total Liabilities and Stockholder's Equity	**$27,151**	$25,914
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2011 and 2010
Georgia Power Company 2011 Annual Report

	2011	2010	2011	2010
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.88% due 2044	**$ -**	$ 206		
Long-term notes payable --				
Variable rate (0.78% at 1/1/11) due 2011	**-**	300		
Variable rate (0.85% to 0.95% at 1/1/12) due 2012	**250**	-		
Variable rate (0.85% to 0.90% at 1/1/12) due 2013	**650**	350		
4.00% to 5.57% due 2011	**-**	103		
5.125% due 2012	**200**	200		
1.30% to 6.00% due 2013	**1,025**	1,025		
5.25% due 2015	**250**	250		
3.00% due 2016	**250**	-		
4.25% to 8.20% due 2017-2048	**4,025**	4,351		
Total long-term notes payable	**6,650**	6,579		
Other long-term debt --				
Pollution control revenue bonds:				
4.40% due 2016	**-**	67		
0.80% to 5.75% due 2018-2048	**916**	1,067		
Variable rate (0.39% at 1/1/11) due 2011	**-**	8		
Variable rate (0.16% at 1/1/12) due 2016	**4**	4		
Variable rate (0.10% to 0.18% at 1/1/12) due 2018-2049	**864**	373		
Total other long-term debt	**1,784**	1,519		
Capitalized lease obligations	**55**	59		
Unamortized debt discount	**(16)**	(17)		
Total long-term debt (annual interest requirement -- $340 million)	**8,473**	8,346		
Less amount due within one year	**455**	415		
Long-term debt excluding amount due within one year	**8,018**	7,931	**46.4%**	46.8%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value -- 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement -- $17 million)	**266**	266	**1.5**	1.6
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,522**	5,291		
Retained earnings	**3,112**	3,063		
Accumulated other comprehensive income (loss)	**(9)**	(11)		
Total common stockholder's equity	**9,023**	8,741	**52.1**	51.6
Total Capitalization	**$ 17,307**	$ 16,938	**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, 2011, 2010, and 2009
Georgia Power Company 2011 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2008	9	$398	$3,656	$2,858	$(33)	$6,879
Net income after dividends on preferred and preference stock	-	-	-	814	-	814
Capital contributions from parent company	-	-	937	-	-	937
Other comprehensive income (loss)	-	-	-	-	12	12
Cash dividends on common stock	-	-	-	(739)	-	(739)
Balance at December 31, 2009	9	398	4,593	2,933	(21)	7,903
Net income after dividends on preferred and preference stock	-	-	-	950	-	950
Capital contributions from parent company	-	-	698	-	-	698
Other comprehensive income (loss)	-	-	-	-	10	10
Cash dividends on common stock	-	-	-	(820)	-	(820)
Balance at December 31, 2010	**9**	**398**	**5,291**	**3,063**	**(11)**	**8,741**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**1,145**	**-**	**1,145**
Capital contributions from parent company	**-**	**-**	**231**	**-**	**-**	**231**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**2**	**2**
Cash dividends on common stock	**-**	**-**	**-**	**(1,096)**	**-**	**(1,096)**
Balance at December 31, 2011	**9**	**$398**	**$5,522**	**$3,112**	**$(9)**	**$9,023**

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 The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing 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, including renewable energy projects, 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, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but 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 generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

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, operations, purchasing, accounting, finance and treasury, tax, information technology, 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 transactions. Costs for these services amounted to $550 million in 2011, $552 million in 2010, and $506 million in 2009. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC 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 $537 million in 2011, $473 million in 2010, and $398 million in 2009.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $171 million, $199 million, and $411 million in 2011, 2010, and 2009, respectively. Additionally, the Company had $16 million and $26 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2011 and 2010, 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 Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $7 million in 2011, $9 million in 2010, and $4 million in 2009. See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2011, 2010, or 2009.

Also see Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO).

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 the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2011	2010	Note
	(in millions)		
Retiree benefit plans	**$ 1,197**	$ 883	(a, i)
Deferred income tax charges	**713**	676	(b)
Deferred income tax charges – Medicare subsidy	**47**	51	(a)
Loss on reacquired debt	**178**	176	(c)
Asset retirement obligations	**108**	69	(b, i)
Fuel-hedging (realized and unrealized) losses	**104**	108	(d)
Vacation pay	**82**	78	(e, i)
Building leases	**43**	45	(f)
Other regulatory assets	**120**	71	(g)
Other cost of removal obligations	**(141)**	(162)	(b)
Deferred income tax credits	**(122)**	(129)	(b)
State income tax credits	**(62)**	-	(h)
Other regulatory liabilities	**(13)**	(1)	(d)
Total assets (liabilities), net	**$ 2,254**	$ 1,865	

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

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 under "Pension Plans" and "Other Postretirement Benefits" and Note 5 under "Current and Deferred Income Taxes" for additional information.

(b) Asset retirement and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2011 other cost of removal obligations included $62 million that is being amortized over a two-year period ending December 31, 2013 in accordance with a Georgia PSC order. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

(c) 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.

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

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

(f) See Note 6 under "Capital Leases." Recovered over the remaining lives of the buildings through 2026.

(g) Recorded and recovered or amortized as approved by the Georgia PSC over periods not exceeding five years.

(h) Additional tax benefits resulting from the Georgia state income tax credit settlement that will be amortized over a 21-month period beginning April 2012, in accordance with a Georgia PSC order. See Note 3 under "Retail Regulatory Matters – Construction – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information.

(i) Not earning a return as offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rate base.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, 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.

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 fuel transportation costs and the cost of purchased emissions 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 as a credit to reduce depreciation 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 accounting standards related to the 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 any 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 cost of funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in millions)	
Generation	**$ 13,675**	$ 12,852
Transmission	**4,355**	4,187
Distribution	**8,125**	7,855
General	**1,621**	1,475
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 27,804**	$ 26,397

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 outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch, respectively. Also, in accordance with a Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.8% in 2011 and 3.0% in 2010 and 2009. Depreciation studies are conducted periodically to update the composite rates that are approved 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. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. 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 are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information related to the Company's cost of removal regulatory liability.

The asset retirement obligation liability primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. 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, including the disposal of polychlorinated biphenyls in certain transformers; 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 in accordance with accounting standards related to asset retirement and environmental 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 additional information on amounts included in rates.

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

	2011	2010
	(in millions)	
Balance at beginning of year	**$ 712**	$ 681
Liabilities incurred	**-**	-
Liabilities settled	**(9)**	(12)
Accretion	**45**	43
Cash flow revisions	**9**	-
Balance at end of year	**$ 757**	$ 712

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. 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 required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. In addition, the NRC prohibits investments in securities of power reactor licensees. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2011 and 2010, approximately $39 million and $141 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $42 million and $144 million at December 31, 2011 and 2010, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2011, investment securities in the Funds totaled $666 million, consisting of equity securities of $244 million, debt securities of $397 million, and $25 million of other securities. At December 31, 2010, investment securities in the Funds totaled $818 million, consisting of equity securities of $258 million, debt securities of $493 million, and $67 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.8 billion, $1.8 billion, and $984 million in 2011, 2010, and 2009, respectively, all of which were reinvested. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $23 million, of which $9 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million related to unrealized losses related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $119 million, of which $118 million is related to securities held in the Funds at December 31, 2009. While the investment securities held in the Funds are reported as trading securities, 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.

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 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 2009. The site study costs and accumulated provisions for decommissioning as of December 31, 2011 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2063	2067
Site study costs:	*(in millions)*	
Radiated structures	$ 583	$ 500
Non-radiated structures	46	71
Total site study costs	$ 629	$ 571
Accumulated provision	$ 399	$ 235

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 as of 2009. The current NRC estimates are $584 million and $426 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. The Georgia PSC approved annual decommissioning costs for ratemaking of $3 million annually for Plant Vogtle Units 1 and 2 for 2009 and 2010 and $2 million annually for Plant Hatch for 2011 through 2013. Based on estimates approved in the 2010 ARP, the Company projects the Funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new 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 2011, 2010, and 2009, the average AFUDC rates were 7.5%, 8.0%, and 8.0%, respectively, and AFUDC capitalized was $134 million, $201 million, and $137 million, respectively. AFUDC, net of income taxes, was 10.4%, 19.0%, and 14.9% of net income after dividends on preferred and preference stock for 2011, 2010, and 2009, respectively. See Note 3 under "Construction – Nuclear" for additional information on the inclusion of construction costs related to the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) in rate base effective January 1, 2011.

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 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 Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Under the 2010 ARP effective January 1, 2011, the Company recovers $18 million annually. In 2009 and 2010, the Company recovered $21 million annually as mandated by the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan). At December 31, 2011, the Company's regulatory asset related to storm damage was $43 million. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. Under the 2010 ARP, effective January 1, 2011, the Company recovers approximately $3 million annually through the environmental compliance cost recovery (ECCR) tariff. In 2009 and 2010, the Company recovered $1 million annually in accordance with the 2007 Retail Rate Plan. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2011, the balance of the environmental remediation liability was $17 million, with approximately $3 million included in other regulatory assets, current and approximately $6 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions 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. Emissions 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 (included 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 excluded from fair value accounting requirements because they qualify for the "normal" scope exception, 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 OCI 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 11 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 had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

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.

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 after dividends on preferred and preference stock, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE must consolidate the related assets and liabilities. The Company had established wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the related investments are reflected as other investments, and the related loans from the trusts are reflected as long-term debt in the balance sheet. In September 2011, the Company redeemed all of the remaining outstanding preferred securities and related trust junior subordinated notes and subsequently dissolved the last trust.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. 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 its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to total approximately $23 million.

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 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.52%	5.93%
Other postretirement benefit plans	**4.87**	5.40	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.25**	7.24	7.35

*Net of estimated investment management expenses of 30 basis points.

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

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, 2011 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 61	$ (51)
Service and interest costs	3	(3)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.7 billion at December 31, 2011 and $2.5 billion at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,674**	$ 2,517
Service cost	**57**	54
Interest cost	**144**	145
Benefits paid	**(132)**	(127)
Actuarial loss (gain)	**166**	85
Balance at end of year	**2,909**	2,674
Change in plan assets		
Fair value of plan assets at beginning of year	**2,621**	2,237
Actual return (loss) on plan assets	**76**	335
Employer contributions	**10**	176
Benefits paid	**(132)**	(127)
Fair value of plan assets at end of year	**2,575**	2,621
Accrued liability	**$ (334)**	$ (53)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $2.8 billion and $148 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in millions)	
Prepaid pension costs	**$ -**	$ 91
Other regulatory assets, deferred	**995**	689
Current liabilities, other	**(10)**	(9)
Employee benefit obligations	**(324)**	(135)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 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 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in millions)	
Prior service cost	**$ 48**	$ 61	**$ 12**
Net (gain) loss	**947**	628	**33**
Other regulatory assets, deferred	**$ 995**	$ 689	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$ 734
Net (gain) loss	(30)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	(13)
Amortization of net gain (loss)	(2)
Total reclassification adjustments	(15)
Total change	(45)
Balance at December 31, 2010	$ 689
Net (gain) loss	**324**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of prior service costs	**(12)**
Amortization of net gain (loss)	**(6)**
Total reclassification adjustments	**(18)**
Total change	**306**
Balance at December 31, 2011	**$ 995**

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

	2011	2010	2009
		(in millions)	
Service cost	**$ 57**	$ 54	$ 48
Interest cost	**144**	145	147
Expected return on plan assets	**(234)**	(220)	(216)
Recognized net loss	**6**	2	2
Net amortization	**12**	13	14
Net periodic pension cost (income)	**$ (15)**	$ (6)	$ (5)

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, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2012	$ 144
2013	149
2014	154
2015	159
2016	165
2017 to 2021	909

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 786**	$ 782
Service cost	**7**	9
Interest cost	**41**	44
Benefits paid	**(48)**	(44)
Actuarial (gain)/loss	**(4)**	(7)
Plan amendments	**(12)**	-
Retiree drug subsidy	**4**	2
Balance at end of year	**774**	786
Change in plan assets		
Fair value of plan assets at beginning of year	**393**	369
Actual return (loss) on plan assets	**(4)**	37
Employer contributions	**20**	29
Benefits paid	**(44)**	(42)
Fair value of plan assets at end of year	**365**	393
Accrued liability	**$ (409)**	$ (393)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in millions)	
Regulatory assets	**$ 186**	$ 179
Employee benefit obligations	**(409)**	(393)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in millions)	
Prior service cost	**$ (4)**	$ 10	**$ -**
Net (gain) loss	**179**	152	**4**
Transition obligation	**11**	17	**6**
Regulatory assets	**$ 186**	$ 179	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$ 202
Net (gain) loss	(13)
Change in prior service costs/transition obligation	-
Reclassification adjustments:	
Amortization of transition obligation	(6)
Amortization of prior service costs	(1)
Amortization of net gain (loss)	(3)
Total reclassification adjustments	(10)
Total change	(23)
Balance at December 31, 2010	$ 179
Net (gain) loss	**29**
Change in prior service costs/transition obligation	**(12)**
Reclassification adjustments:	
Amortization of transition obligation	**(6)**
Amortization of prior service costs	**(1)**
Amortization of net gain (loss)	**(3)**
Total reclassification adjustments	**(10)**
Total change	**7**
Balance at December 31, 2011	**$ 186**

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

	2011	2010	2009
		(in millions)	
Service cost	**$ 7**	$ 9	$ 10
Interest cost	**41**	44	50
Expected return on plan assets	**(30)**	(30)	(30)
Net amortization	**11**	10	13
Net postretirement cost	**$ 29**	$ 33	$ 43

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2012	$ 49	$ (4)	$ 45
2013	51	(5)	46
2014	54	(5)	49
2015	56	(6)	50
2016	58	(7)	51
2017 to 2021	298	(38)	260

Benefit Plan Assets

Pension plan and other postretirement benefit 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). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**-**	-
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**39%**	41%
International equity	21	**22**	24
Domestic fixed income	25	**26**	30
Global fixed income	7	**8**	-
Special situations	1	**-**	-
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private-market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are included in real estate investments and private equities in the tables below.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 437	$ 202	$ -	$ 639
International equity*	449	129	-	578
Fixed income:				
U.S. Treasury, government, and agency bonds	-	164	-	164
Mortgage- and asset-backed securities	-	51	-	51
Corporate bonds	-	316	1	317
Pooled funds	-	144	-	144
Cash equivalents and other	-	53	-	53
Real estate investments	83	-	296	379
Private equity	-	-	220	220
Total	$ 969	$ 1,059	$ 517	$ 2,545

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 486	$ 196	$ -	$ 682
International equity*	490	170	-	660
Fixed income:				
U.S. Treasury, government, and agency bonds	-	117	-	117
Mortgage- and asset-backed securities	-	95	-	95
Corporate bonds	-	226	1	227
Pooled funds	-	77	-	77
Cash equivalents and other	1	183	-	184
Real estate investments	71	-	258	329
Private equity	-	-	245	245
Total	$ 1,048	$ 1,064	$ 504	$ 2,616

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$ 258**	**$ 245**	$ 217	$ 221
Actual return on investments:				
Related to investments held at year end	**24**	**(5)**	15	18
Related to investments sold during the year	**8**	**14**	7	7
Total return on investments	**32**	**9**	22	25
Purchases, sales, and settlements	**6**	**(34)**	19	(1)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 296**	**$ 220**	$ 258	$ 245

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 85	$ 24	$ -	$ 109
International equity*	15	31	-	46
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5	-	5
Mortgage- and asset-backed securities	-	1	-	1
Corporate bonds	-	10	-	10
Pooled funds	-	38	-	38
Cash equivalents and other	-	26	-	26
Trust-owned life insurance	-	131	-	131
Real estate investments	3	-	9	12
Private equity	-	-	7	7
Total	$ 103	$ 266	$ 16	$ 385

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2010:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 98	$ 33	$ -	$ 131
International equity*	16	39	-	55
Fixed income:				
U.S. Treasury, government, and agency bonds	-	4	-	4
Mortgage- and asset-backed securities	-	3	-	3
Corporate bonds	-	7	-	7
Pooled funds	-	28	-	28
Cash equivalents and other	-	11	-	11
Trust-owned life insurance	-	132	-	132
Real estate investments	2	-	8	10
Private equity	-	-	8	8
Total	$ 116	$ 257	$ 16	$ 389

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011 Real Estate Investments	**2011** Private Equity	2010 Real Estate Investments	2010 Private Equity
		(in millions)		
Beginning balance	**$ 8**	**$ 8**	$ 8	$ 8
Actual return on investments:				
Related to investments held at year end	**1**	**-**	-	-
Related to investments sold during the year	**-**	**-**	-	-
Total return on investments	**1**	**-**	-	-
Purchases, sales, and settlements	**-**	**(1)**	-	-
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 9**	**$ 7**	$ 8	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $24 million, $23 million, and $25 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 such as regulation of air emissions and water discharges. 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 air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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 ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 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. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations 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, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit 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 allege 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 some of the defendants (including Southern Company) 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.

In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. 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. See Note 1 under "Environmental Remediation Recovery" for additional information.

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 cleanup and 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; however, they are not expected to have a material impact on the Company's financial statements.

In 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 regarding this site from the EPA.

On September 29, 2011, the EPA issued a unilateral administrative order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the Ward Transformer Superfund site. The Company does not believe it is a liable party under CERCLA based on its alleged connection to the site. As a result, on November 7, 2011, the Company filed a response with the EPA indicating that the Company is not willing to undertake the work set forth in the UAO because the Company has sufficient cause to believe it is not a liable party. On November 22, 2011, the EPA sent the Company a letter stating that the EPA does not consider the Company to be in compliance with the UAO. The EPA also stated that it is considering enforcement options against the Company and other UAO recipients who are not complying with the UAO.

The EPA may seek to enforce the UAO in court pursuant to its enforcement authority under CERCLA and may seek recovery of its costs in undertaking the UAO work. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at the Ward Transformer Superfund site, in 2009, the Company, along with many other parties, was sued by several existing PRPs for cost recovery for a removal action that is currently taking place. The Company and numerous other defendants moved for a dismissal of these lawsuits. The court denied the dismissal of the lawsuits in March 2010 but granted the Company's motion regarding the dismissal of the claim pertaining to the plaintiffs' joint and several liability.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment, described in Note 1 under "Environmental Remediation Recovery," it is not expected to have a material impact on the Company's financial statements.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company also filed similar claims for the years 2002 through 2004. In 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, the Company and the Georgia Department of Revenue (DOR) agreed to a settlement resolving the claims. As a result, the Company recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, the Company recorded a reduction of approximately $23 million in related interest expense. See Note 3 under "Construction – Other Construction" herein for additional information on the regulatory liability.

Nuclear Fuel Disposal Costs

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

In 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Company's portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit. The Company filed a motion for summary judgment related to a portion of the costs, which remains pending.

In 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. 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, 2011 for either claim.

The final outcome of these matters cannot be determined at this time, but no material impact on the Company's 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 Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff (Advocacy Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been or will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Construction – Other Construction" herein for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

2011 Integrated Resource Plan Update

On August 4, 2011, the Company filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included the Company's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. The Company also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, the Company is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 megawatts (MWs) of capacity. The Company is currently updating its economic analysis of these units based on the final Mercury and Air Toxics Standards (MATS) rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, the Company cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes the Company's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process. If approved, these PPAs are expected to result in contractual obligations of approximately $84 million in 2015, $102 million in 2016, and $1.4 billion thereafter.

In addition, the Company filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, the Company entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on the Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in the Company's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

The Company's under recovered fuel balance totaled approximately $137 million at December 31, 2011, all of which is included in current assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Construction

Nuclear

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to Plant Vogtle Units 3 and 4. See Note 4 for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows 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. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. The Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, the Company's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve the Company's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse 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 MWs 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 agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. 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 is 45.7%.

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 Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse 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 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 COLs 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.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and the Company (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and the Company expects the Consortium to seek recovery of these costs. The Company is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. The Company has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and the Company intends to vigorously defend itself in these matters. The Company expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, the Company would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and the Company (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC's issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

The Company is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. The Company completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between the Company and the Georgia PSC Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "PSC Matters – Rate Plans" herein for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

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 these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $141 million in 2011, $100 million in 2010, and $87 million in 2009 and is included in purchased power from affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with OPC, MEAG Power, 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 Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2011, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$ 3,296	$ 1,962
Plant Hatch (nuclear)	50.1	978	545
Plant Wansley (coal)	53.5	709	225
Plant Scherer (coal)			
Units 1 and 2	8.4	157	76
Unit 3	75.0	1,108	373
Rocky Mountain (pumped storage)	25.4	175	113
Intercession City (combustion-turbine)	33.3	12	4

At December 31, 2011, the Company's portion of construction work in progress related to environmental projects at Plants Wansley and Scherer was $36 million and $63 million, respectively. 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

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state 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 federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in millions)	
Federal –			
Current	**$ 106**	$ 147	$ 211
Deferred	**479**	312	175
	585	459	386
State –			
Current	**19**	(36)	7
Deferred	**21**	30	17
	40	(6)	24
Total	**$ 625**	$ 453	$ 410

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:

	2011	2010
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 3,687**	$ 3,184
Property basis differences	**804**	746
Employee benefit obligations	**257**	251
Fuel clause under recovery	**56**	162
Premium on reacquired debt	**72**	71
Regulatory assets associated with employee benefit obligations	**481**	336
Asset retirement obligations	**299**	275
Other	**103**	70
Total	**5,759**	5,095
Deferred tax assets –		
Federal effect of state deferred taxes	**157**	159
Employee benefit obligations	**585**	433
Other property basis differences	**106**	111
Other deferred costs	**55**	72
Cost of removal obligations	**40**	52
State tax credit carry forward	**52**	192
Unbilled fuel revenue	**45**	57
Asset retirement obligations	**299**	275
Other	**63**	44
Total	**1,402**	1,395
Total deferred tax liabilities, net	**4,357**	3,700
Portion included in current assets/(liabilities), net	**31**	18
Accumulated deferred income taxes	**$ 4,388**	$ 3,718

At December 31, 2011, tax-related regulatory assets were $760 million. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $51 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The Company began amortizing the regulatory asset in 2011 to income tax expense over 12 years under the 2010 ARP.

At December 31, 2011, tax-related regulatory liabilities to be credited to customers were $184 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. In 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia DOR resolving claims for tax credits in its 2005 through 2009 income tax filings. See Note 3 under "Income Tax Matters" for additional information.

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 $9 million in 2011, $13 million in 2010, and $14 million in 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.5**	(0.3)	1.2
Non-deductible book depreciation	**0.8**	1.0	1.1
AFUDC equity	**(1.9)**	(3.6)	(2.7)
Donations	**-**	-	(0.8)
Other	**(0.5)**	(0.2)	(0.8)
Effective income tax rate	**34.9%**	31.9%	33.0%

The increase in the Company's 2011 effective tax rate is primarily the result of decreases in non-taxable AFUDC equity and state tax credits. The decrease in the Company's 2010 effective tax rate from 2009 is primarily the result of an increase in non-taxable AFUDC equity, an increase in state tax credits earned on ongoing construction projects, and a decrease in tax deductions related to unrecognized tax benefits. See "Unrecognized Tax Benefits" herein for additional information on unrecognized tax benefits related to state tax credits.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $190 million, resulting in a balance of $47 million as of December 31, 2011.

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

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 237**	$ 181	$ 137
Tax positions from current periods	**9**	52	44
Tax positions increase from prior periods	**-**	27	6
Tax positions decrease from prior periods	**(87)**	(23)	(5)
Reductions due to settlements	**(112)**	-	-
Reductions due to expired statute of limitations	**-**	-	(1)
Balance at end of year	**$ 47**	$ 237	$ 181

The tax positions from current periods for 2011 relate primarily to the tax accounting method change for repairs-generation assets, and other miscellaneous tax positions. The tax positions decrease from prior periods and reductions due to settlements for 2011 relate to the settlement of the Georgia state tax credit litigation on June 10, 2011. See Note 3 under “Income Tax Matters – Georgia State Income Tax Credits” for additional information. In addition, the tax positions decrease from prior periods for 2011 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See “Tax Method of Accounting for Repairs” herein for additional information.

The impact on the Company’s effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$ 28**	$ 202	$ 181
Tax positions not impacting the effective tax rate	**19**	35	-
Balance of unrecognized tax benefits	**$ 47**	$ 237	$ 181

The tax positions impacting the effective tax rate for 2011 relate primarily to the production activities deduction and other miscellaneous tax positions. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See “Tax Method of Accounting for Repairs” herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$ 27**	$ 20	$ 14
Interest reclassified due to settlements	**(24)**	-	-
Interest accrued during the year	**3**	7	6
Balance at end of year	**$ 6**	$ 27	$ 20

The Company classifies interest on tax uncertainties as interest expense. The interest for all years presented was primarily associated with the state tax credit litigation settled on June 10, 2011. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company’s unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs - generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $133 million for the Company. On August 19, 2011, the IRS issued a revenue procedure which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs - transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company 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 constituted substantially all of the assets of these trusts and were reflected in the balance sheet as long-term debt at December 31, 2010. The Company considered that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constituted a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2010, trust preferred securities of $200 million were outstanding. In September 2011, the Company redeemed all of the preferred securities and the related trust junior subordinated notes. 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 scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2011	2010
	(in millions)	
Capital lease	**$ 5**	$ 4
Bank term loans	**250**	300
Pollution control revenue bonds	**-**	8
Senior notes	**200**	100
Other long-term debt	**-**	3
Total	**$ 455**	$ 415

Maturities through 2016 applicable to total long-term debt are as follows: $455 million in 2012; $1.7 billion in 2013; $5 million in 2014; $256 million in 2015; and $260 million in 2016.

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, 2011 and 2010 was $1.8 billion and $1.5 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued $550 million aggregate principal amount of unsecured senior notes in 2011. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2011 and 2010, the Company had $6.4 billion and $6.3 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $55 million and $59 million at December 31, 2011 and 2010, respectively.

Bank Term Loans

At December 31, 2011 and 2010, the Company had $450 million and $300 million of bank loans outstanding, respectively. At December 31, 2011, $200 million of the bank loans outstanding were short-term instruments and are reflected in notes payable on the balance sheet.

Subsequent to December 31, 2011, the Company entered into a six-month short-term floating rate bank loan in an aggregate principal amount of $100 million bearing interest based on one-month London Interbank Offered Rate (LIBOR).

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2011, the Company was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the Company. The Company is currently in compliance with all such covenants.

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, 2011 and 2010, the Company had a capitalized lease obligation for its corporate headquarters building of $55 million and $58 million, respectively, with an interest rate of 7.4% and 8.0%, respectively. 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. The annual expense incurred for all capital leases was not material for any year presented.

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 five 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 through the first par redemption date.

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, 2011, committed credit arrangements with banks were as follows:

Expires[a]			
2014	2016	Total	Unused
(in millions)			
$250	$1,500	$1,750	$1,745

(a) No credit arrangements expire in 2012, 2013, or 2015.

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 1/4 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 certain 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, 2011, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.7 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, 2011 was $868 million.

The Company has short-term borrowings primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

Details of short-term borrowings, excluding $2 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$ 313	0.20%	$ 208	0.26%	$ 681
Short-term bank debt	200	1.18%	9	1.18%	200
Total	$ 513	0.51%	$ 217	0.33%	
December 31, 2010:					
Commercial paper	$ 575	0.30%	$ 167	0.325%	$ 575

(a) Average and maximum amounts are based upon daily balances during the period.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $2.3 billion, $2.4 billion, and $2.1 billion for 2012, 2013, and 2014, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $237 million, $249 million, and $228 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's MATS rule and the proposed water and coal combustion byproducts rules. The construction program is 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; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, 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; project scope and design changes; storm impacts; 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, 2011, significant purchase commitments were outstanding in connection with the continuous construction program. See Note 3 under "Construction" for additional information on the portion of the Company's continuous construction program associated with new generation.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for 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 are currently estimated at $143 million over the remaining term of the LTSA, which is currently projected to be approximately seven years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has a 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 $4.5 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 at Plant McDonough. Unit 4 went into service on December 28, 2011 and Units 5 and 6 are scheduled to go into service in May and November 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 began 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, which are subject to price escalation, are currently estimated to be $557 million for the term of this agreement which is expected to be 15 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 entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization 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 2.7 million tons, equating to approximately $75 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $18 million in 2012, $18 million in 2013, $18 million in 2014, $10 million in 2015, and $3 million in 2016.

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 emissions 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, 2011.

Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2012	$ 546	$ 1,473	$ 257
2013	647	1,121	167
2014	501	494	163
2015	420	308	102
2016	406	153	71
2017 and thereafter	2,179	238	528
Total	$ 4,699	$ 3,787	$ 1,288

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $120 million, $106 million, and $82 million for the years 2011, 2010, and 2009, 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 credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power'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, non-affiliates in the statements of income. Capacity payments totaled $52 million, $55 million, and $54 million in 2011, 2010, and 2009, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2011 were as follows:

	Vogtle Capacity Payments	Affiliated PPAs	Non-Affiliated PPAs
		(in millions)	
2012	$ 50	$ 108	$ 104
2013	23	109	111
2014	20	109	112
2015	11	109	121
2016	11	110	126
2017 and thereafter	78	275	1,493
Total	$ 193	$ 820	$ 2,067

- Certain PPAs reflected in the table are accounted for as operating leases.
- Excludes four PPAs that are subject to certification by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – 2011 Integrated Resource Plan Update" for additional information.

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $33 million for 2011, $35 million for 2010, and $43 million for 2009.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2012	$ 27	$ 7	$ 34
2013	23	6	29
2014	18	5	23
2015	13	3	16
2016	8	1	9
2017 and thereafter	7	1	8
Total	$ 96	$ 23	$ 119

In addition to the above rental commitments, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These operating leases expire in 2014 and 2018 and the Company's maximum obligation is approximately $10 million and $24 million, respectively. 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. Estimated annual commitments for the three-year lease and seven-year lease are approximately $1 million and $2 million, respectively. 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. 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 obligations.

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 $25 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 COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 1,722 current and former employees of the Company participating in the stock option program, and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options 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 Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted 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. Southern 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	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2010	10,381,933	$32.44
Granted	1,264,485	37.99
Exercised	(3,686,300)	31.56
Cancelled	(7,531)	32.19
Outstanding at December 31, 2011	**7,952,587**	**$33.73**
Exercisable at December 31, 2011	**5,245,143**	**$33.42**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $100 million and $68 million, respectively.

As of December 31, 2011, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

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 amounts were not material for any year presented.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $32 million, $12 million, and $2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any of the years presented.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 185,512. During 2011, 168,748 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 28,302 performance share units were forfeited resulting in 325,958 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units and the related tax benefit recognized in income were not material. As of December 31, 2011, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months was not material.

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 Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $12.6 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 $375 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' operating 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 deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

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 $69 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 debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

Fair value measurements are 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 and reflects 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.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 13	$ -	$ 13
Nuclear decommissioning trusts:[(a)]				
Domestic equity	143	1	-	144
Foreign equity	100	-		100
U.S. Treasury and government agency securities	-	25	-	25
Municipal bonds	-	82	-	82
Corporate bonds	-	167	-	167
Mortgage and asset backed securities	-	123	-	123
Other investments	-	25	-	25
Cash equivalents	13	-	-	13
Total	$ 256	$ 436	$ -	$ 692
Liabilities:				
Energy-related derivatives	$ -	$ 95	$ -	$ 95

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 1	$ -	$ 1
Nuclear decommissioning trusts:[(a)]				
Domestic equity	257	1	-	258
U.S. Treasury and government agency securities	-	213	-	213
Municipal bonds	-	53	-	53
Corporate bonds	-	138	-	138
Mortgage and asset backed securities	-	89	-	89
Other investments	-	67	-	67
Total	$ 257	$ 562	$ -	$ 819
Liabilities:				
Energy-related derivatives	$ -	$ 101	$ -	$ 101

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and LIBOR interest rates. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2011:	*(in millions)*			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$32	None	Daily	1 to 3 days
Other – commingled funds	25	None	Daily	Not applicable
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$65	None	Daily	1 to 3 days
Other – commingled funds	67	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2011	**$ 8,418**	**$ 9,209**
2010	$ 8,285	$ 8,548

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. 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 testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

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 and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – 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.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for natural gas positions totaled 73 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

The Company also enters into interest rate 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 where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2011 and 2010, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are not expected to have a material impact on the Company's financial statements. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 8**	$ 1	Liabilities from risk management activities	**$ 68**	$ 77
	Other deferred charges and assets	**5**	-	Other deferred credits and liabilities	**27**	24
Total derivatives designated as hedging instruments for regulatory purposes		**$ 13**	$ 1		**$ 95**	$ 101

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (68)**	$ (77)	Other regulatory liabilities, current	**$ 8**	$ 1
	Other regulatory assets, deferred	**(27)**	(24)	Other deferred credits and liabilities	**5**	-
Total energy-related derivative gains (losses)		**$ (95)**	$(101)		**$ 13**	$ 1

The pre-tax effect of gains (losses) related to interest rate derivatives designated as cash flow hedging instruments recognized in OCI was not material for any year presented. Gains (losses) reclassified from accumulated OCI into income were as follows:

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

	Amount		
Statements of Income Location	**2011**	2010	2009
		(in millions)	
Interest expense, net of amounts capitalized	**$ (4)**	$ (16)	$ (22)

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

Contingent Features

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 derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $13 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2011	**$ 1,989**	**$ 393**	**$ 206**
June 2011	**2,265**	**537**	**309**
September 2011	**2,788**	**895**	**520**
December 2011	**1,758**	**222**	**110**
March 2010	$ 1,984	$ 399	$ 238
June 2010	2,000	411	238
September 2010	2,628	714	420
December 2010	1,737	141	54

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

SELECTED FINANCIAL AND OPERATING DATA 2007-2011

Georgia Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues **(in millions)**	**$8,800**	$8,349	$7,692	$8,412	$7,572
Net Income After Dividends					
on Preferred and Preference Stock **(in millions)**	**$1,145**	$950	$814	$903	$836
Cash Dividends					
on Common Stock **(in millions)**	**$1,096**	$820	$739	$721	$690
Return on Average Common Equity **(percent)**	**12.89**	11.42	11.01	13.56	13.50
Total Assets **(in millions)**	**$27,151**	$25,914	$24,295	$22,316	$20,823
Gross Property Additions **(in millions)**	**$1,981**	$2,401	$2,646	$1,953	$1,862
Capitalization **(in millions)**:					
Common stock equity	**$9,023**	$8,741	$7,903	$6,879	$6,435
Preferred and preference stock	**266**	266	266	266	266
Long-term debt	**8,018**	7,931	7,782	7,006	5,938
Total (excluding amounts due within one year)	**$17,307**	$16,938	$15,951	$14,151	$12,639
Capitalization Ratios **(percent)**:					
Common stock equity	**52.1**	51.6	49.5	48.6	50.9
Preferred and preference stock	**1.5**	1.6	1.7	1.9	2.1
Long-term debt	**46.4**	46.8	48.8	49.5	47.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers **(year-end)**:					
Residential	**2,047,390**	2,049,770	2,043,661	2,039,503	2,024,520
Commercial	**296,143**	296,140	295,375	295,925	295,478
Industrial	**8,279**	8,136	8,202	8,248	8,240
Other	**7,521**	7,309	6,580	5,566	4,807
Total	**2,359,333**	2,361,355	2,353,818	2,349,242	2,333,045
Employees **(year-end)**	**8,310**	8,330	8,599	9,337	9,270

SELECTED FINANCIAL AND OPERATING DATA 2007-2011 (continued)
Georgia Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$ 3,241**	$3,072	$2,686	$2,648	$2,443
Commercial	**3,217**	3,011	2,826	2,917	2,576
Industrial	**1,547**	1,441	1,318	1,640	1,404
Other	**94**	84	82	81	75
Total retail	**8,099**	7,608	6,912	7,286	6,498
Wholesale - non-affiliates	**341**	380	395	569	538
Wholesale - affiliates	**32**	53	112	286	278
Total revenues from sales of electricity	**8,472**	8,041	7,419	8,141	7,314
Other revenues	**328**	308	273	271	258
Total	**$8,800**	$8,349	$7,692	$8,412	$7,572
Kilowatt-Hour Sales (in millions):					
Residential	**27,223**	29,433	26,272	26,412	26,840
Commercial	**32,900**	33,855	32,593	33,058	33,057
Industrial	**23,519**	23,209	21,810	24,164	25,490
Other	**657**	663	671	671	697
Total retail	**84,299**	87,160	81,346	84,305	86,084
Wholesale - non-affiliates	**3,904**	4,662	5,208	9,755	10,578
Wholesale - affiliates	**626**	1,000	2,504	3,695	5,192
Total	**88,829**	92,822	89,058	97,755	101,854
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.91**	10.44	10.22	10.03	9.10
Commercial	**9.78**	8.89	8.67	8.82	7.79
Industrial	**6.58**	6.21	6.04	6.79	5.51
Total retail	**9.61**	8.73	8.50	8.64	7.55
Wholesale	**8.23**	7.65	6.57	6.36	5.17
Total sales	**9.54**	8.66	8.33	8.33	7.18
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,288**	14,367	12,848	12,969	13,315
Residential Average Annual Revenue Per Customer	**$1,582**	$1,499	$1,314	$1,300	$1,212
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**16,588**	15,992	15,995	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	**14,800**	15,614	15,173	14,221	13,817
Summer	**16,941**	17,152	16,080	17,270	17,974
Annual Load Factor (percent)	**59.5**	60.9	60.7	58.4	57.5
Plant Availability (percent):					
Fossil-steam	**88.6**	88.6	92.5	91.0	90.8
Nuclear	**92.2**	94.0	88.4	89.8	92.4
Source of Energy Supply (percent):					
Coal	**44.4**	51.8	52.3	58.7	61.5
Nuclear	**16.6**	16.4	16.2	14.8	14.6
Hydro	**1.1**	1.4	1.8	0.6	0.5
Oil and gas	**8.9**	8.0	7.7	5.1	5.5
Purchased power -					
From non-affiliates	**6.1**	5.2	4.4	5.1	3.8
From affiliates	**22.9**	17.2	17.6	15.7	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

Directors

W. Paul Bowers
President and Chief Executive Officer
Georgia Power Company

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

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

Thomas A. Fanning
Chairman, President, and Chief Executive Officer
The Southern Company

Stephen S. Green
President and Chief Executive Officer
Stephen Green Properties, Inc.

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

Charles K. Tarbutton
Assistant Vice President
Sandersville Railroad Company

Beverly Daniel Tatum
President
Spelman College

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

Richard W. Ussery
Retired (1/2006)
(Total System Services, Inc.)

E. Jenner Wood III
Chairman, President, and Chief Executive Officer
Atlanta/Georgia Division of SunTrust Bank

Officers

W. Paul Bowers
President and Chief Executive Officer
Georgia Power Company

W. Craig Barrs
Executive Vice President
External Affairs

Mickey A. Brown (Retired effective 12/31/2011)
Executive Vice President
Customer Service Organization

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer,
and Treasurer

Joseph A. (Buzz) Miller
Executive Vice President
Nuclear Development

Anthony L. Wilson (Elected effective 1/1/2012)
Executive Vice President
Customer Service and Operations

Michael K. Anderson (Elected effective 1/8/2011)
Senior Vice President
Charitable Giving

Thomas P. Bishop
Senior Vice President, Compliance Officer,
General Counsel, and Corporate Secretary

Walter Dukes (Elected effective 1/1/2012)
Senior Vice President
Metro Atlanta Regions

Stan W. Connally
Senior Vice President
Fossil & Hydro Generation and
Senior Production Officer

Richard L. Holmes (Retired effective 12/31/2011)
Senior Vice President
Metro Region

Christopher T. Bell (Resigned effective 12/31/2011)
Vice President
Energy Planning and Sales

Rebecca A. Blalock (Retired effective 10/1/2011)
Vice President
Information Resources

Melissa K. Caen
Assistant Secretary

Moanica M. Caston (Elected effective 1/8/2011)
Vice President
Diversity

Lenn H. Chandler (Elected effective 1/1/2012)
Region Vice President
Northeast

Pedro P. Cherry (Elected effective 1/1/2012)
Vice President
Community and Economic Development

P. Mike Clanton
Vice President
Land

Kenneth E. Coleman (Elected effective 8/17/2011 and resigned effective 11/16/2011)
Vice President
Information Technology

Jason T. Cuevas (Elected effective 2/5/2011)
Vice President
Corporate Communication

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

J. Truitt Eavenson
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher (Retired effective 10/31/2011)
Vice President
Community and Economic Development

Jim R. Fletcher (Elected effective 2/5/2011)
Vice President
Governmental and Regulatory Affairs

Jeff G. Franklin (Resigned effective 8/1/2011)
Vice President
Governmental Affairs

Michael A. Hazelton (Elected effective 1/8/2011)
Vice President
Marketing

Cathy P. Hill
Region Vice President
Coastal

Gerald L. Johnson
Vice President
Customer Services

Anne H. Kaiser
Region Vice President
Northwest

Stacy R. Kilcoyne
Vice President
Human Resource Services

Danny W. Lindsey (Elected effective 1/1/2012)
Vice President
Transmission

Earl C. Long
Assistant Treasurer

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery (Retired effective 4/6/2011)
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Robert B. Morris (Resigned effective 10/31/2011)
Assistant Comptroller and Assistant Secretary

Leonard Owens (Elected effective 1/17/2012)
Vice President
Human Resources

Laura I. Patterson (Elected Assistant Secretary effective 11/1/2011)
Assistant Comptroller and Assistant Secretary

Gregory N. Roberts (Elected effective 6/9/2011)
Vice President
Pricing and Planning

Louise L. Scott (Elected effective 11/16/2011)
Vice President
Information Technology

Ronald Shipman (Elected effective 1/8/2011)
Vice President
Environmental Affairs

Leslie R. Sibert
Vice President
Distribution

Elliott L. Spencer (Elected effective 11/1/2011)
Assistant Comptroller

H. Murry Weaver (Elected effective 1/1/2012)
Vice President
Sales

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright (Resigned effective 2/5/2011)
Vice President
Corporate Communications

James D. Wynn, Jr. (Elected effective 1/8/2011)
Vice President
Corporate Services

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

Profile
The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.4 million customers within its service area. In 2011, retail energy sales accounted for 95% of the Company's total sales of 88.8 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
The Bank of New York Mellon
101 Barclay Street, 8 West
New York, New York 10286

Registrar, Transfer Agent, and Dividend Paying Agent
For Preferred Stock and Preference Stock
Computershare
Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252
(800) 554-7626

www.bnymellon.com/shareowner/equityaccess

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	2011	2010
	(in thousands)	
First	$224,025	$205,000
Second	224,025	205,000
Third	224,025	205,000
Fourth	424,025	205,000

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 without charge upon written request to the office of the Corporate Secretary. Requests for copies should be directed to the Corporate Secretary, 241 Ralph McGill Boulevard, N.E., Atlanta, GA 30308-3374. For additional information, contact the office of the Corporate Secretary at (404) 506-7455.

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

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, GA 30303

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

[THIS PAGE INTENTIONALLY LEFT BLANK]