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LABAMA POWER COMPANY

2011 Annual Report

ALABAMA POWER
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2011 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

Charles D. McCrary
President and Chief Executive Officer

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 24, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of 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 28 to 34) referred to above present fairly, in all material respects, the financial position of Alabama 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

Birmingham, Alabama
February 24, 2012

OVERVIEW

Business Activities

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

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

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than 1.4 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 fossil/hydro 2011 Peak Season EFOR, excluding the impact of tornadoes in April 2011, 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 performance for 2011 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	1.09%
Net Income After Dividends on Preferred and Preference Stock	$705 million	$708 million

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 of $708 million increased $1 million (0.1%) over the prior year. The increase was due to a reduction in other operations and maintenance expenses, an increase in revenues under rate certificated new plant environmental (Rate CNP Environmental) associated with the completion of construction projects related to environmental mandates, and an increase in industrial kilowatt-hour (KWH) sales. The increases in net income were partially offset by reductions in wholesale revenues from sales to non-affiliates, decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, and a reduction in allowance for funds used during construction (AFUDC) equity.

The Company's 2010 net income after dividends on preferred and preference stock of $707 million increased $37 million (5.5%) over the prior year. The increase was primarily due to increases in rates under the rate stabilization and equalization plan (Rate RSE) and the Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. The increases in retail revenues were partially offset by increases in operations and maintenance expenses, increases in depreciation and amortization, and reductions in wholesale revenues from sales to non-affiliates and AFUDC equity.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$5,702**	**$(274)**	$447
Fuel	**1,679**	**(172)**	27
Purchased power	**271**	**(9)**	(27)
Other operations and maintenance	**1,262**	**(156)**	207
Depreciation and amortization	**637**	**31**	61
Taxes other than income taxes	**339**	**7**	10
Total operating expenses	**4,188**	**(299)**	278
Operating income	**1,514**	**25**	169
Total other income and (expense)	**(289)**	**(9)**	(53)
Income taxes	**478**	**15**	79
Net income	**747**	**1**	37
Dividends on preferred and preference stock	**39**	**-**	-
Net income after dividends on preferred and preference stock	**$ 708**	**$ 1**	$ 37

Operating Revenues

Operating revenues for 2011 were $5.7 billion, reflecting a $274 million decrease from 2010. Details of operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail – prior year	**$5,076**	$4,497
Estimated change in –		
Rates and pricing	**88**	310
Sales growth (decline)	**42**	(11)
Weather	**(147)**	199
Fuel and other cost recovery	**(87)**	81
Retail – current year	**4,972**	5,076
Wholesale revenues –		
Non-affiliates	**287**	465
Affiliates	**244**	236
Total wholesale revenues	**531**	701
Other operating revenues	**199**	199
Total operating revenues	**$5,702**	$5,976
Percent change	**(4.6)%**	8.1%

Retail revenues in 2011 were $5.0 billion. These revenues decreased $104 million (2.0%) in 2011 and increased $579 million (12.9%) in 2010 as compared to the prior period. The decrease was due to closer to normal weather in 2011 compared to 2010 and a reduction in fuel revenues when compared to the corresponding period in 2010. The decreases were partially offset by increased revenues associated with Rate CNP Environmental for the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under the Company's rate structure. The increase in 2010 was due to increases in rates and pricing under Rate RSE and Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

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

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

	2011	2010	2009
		(in millions)	
Unit power sales –			
Capacity	**$ -**	$ 84	$158
Energy	**6**	95	207
Total	**6**	179	365
Other power sales –			
Capacity and other	**148**	148	133
Energy	**133**	138	122
Total	**281**	286	255
Total non-affiliated	**$287**	$465	$620

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available 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 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.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to Florida utilities and sales to wholesale customers within the Company's service territory. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in the prices of oil and natural gas, which are the primary fuel sources for unit power sales customers, influence changes in these energy sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings.

In May 2010, the long-term unit power sales contracts expired and the unit power energy sales and capacity revenues ceased, except for adjustments, which resulted in a reduction of wholesale revenues from sales to non-affiliates in 2011 and 2010. Beginning in June 2010, such capacity subject to the unit power sales contracts became available for retail service. In 2011, wholesale revenues from sales to non-affiliates decreased $178 million (38.3%) reflecting a $94 million decrease in revenue from energy sales and a $84 million decrease in capacity revenues. KWH sales decreased 46.9%, partially offset by a 15.3% increase in the price of energy. In 2010, wholesale revenues from sales to non-affiliates decreased $155 million (25.0%) reflecting a $96 million decrease in revenue from energy sales and a $59 million decrease in capacity revenues. KWH sales decreased 39.5%. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

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). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses. The changes in wholesale revenues from sales to affiliates for 2011 and 2010 were not material.

In 2011, other operating revenues were $199 million. The change from prior year revenues was not material. Other operating revenues increased $24 million (13.7%) in 2010 due to a $13 million increase in transmission sales and a $12 million increase in revenues from gas-fueled co-generation steam facilities as a result of greater sales volume. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 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	**18.6**	**(8.7)%**	13.0%	**0.6%**	(0.6)%
Commercial	**14.2**	**(3.7)**	3.8	**(0.6)**	(1.1)
Industrial	**21.7**	**5.1**	11.1	**5.1**	11.1
Other	**0.2**	**(0.9)**	(0.8)	**(0.9)**	(0.8)
Total retail	**54.7**	**(2.3)**	9.7	**2.0%**	3.5%
Wholesale -					
Non-affiliates	**4.6**	**(46.9)**	(39.5)		
Affiliates	**7.0**	**15.3**	(6.2)		
Total wholesale	**11.6**	**(21.3)**	(29.2)		
Total energy sales	**66.3**	**(6.2)%**	(1.6)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2011 were 2.3% less than in 2010. Energy sales were down in 2011 in the residential and commercial customer classes and up in the industrial customer class. Residential and commercial sales decreased 8.7% and 3.7%, respectively, due primarily to closer to normal weather in 2011 compared to 2010. Industrial sales increased 5.1% in 2011 as a result of increased customer demand, primarily in the primary metals, which includes fabricated pipe and metals, and chemicals sectors, due to a recovering economy.

Retail energy sales in 2010 were 9.7% greater than in 2009. Energy sales were up in 2010 across major classes of customers. Residential and commercial sales increased 13.0% and 3.8%, respectively, due primarily to significant weather-driven increases in KWH sales as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010. Industrial sales increased 11.1% in 2010 as a result of increased customer demand in most major sectors, including primary metals, chemicals, transportation, and textiles sectors, due to a recovering economy.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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

Fuel and purchased power expenses generally do not affect net income, since they are offset by fuel revenues under the Company's energy cost recovery rate (Rate ECR). The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Details of the Company's electricity generated and purchased were as follows:

	2011	2010	2009
Total generation *(billions of KWHs)*	**64.8**	69.2	68.8
Total purchased power *(billions of KWHs)*	**4.7**	5.0	6.3
Sources of generation *(percent)* –			
Coal	**56**	61	58
Nuclear	**22**	19	20
Gas	**17**	15	13
Hydro	**5**	5	9
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.16**	3.02	3.02
Nuclear	**0.66**	0.60	0.56
Gas	**3.92**	4.47	5.24
Average cost of fuel, generated *(cents per net KWH)**	**2.70**	2.76	2.79
Average cost of purchased power *(cents per net KWH)***	**6.04**	6.42	6.05

* KWHs generated by hydro are excluded from the average cost of fuel, generated.
** 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 $2.0 billion in 2011, a decrease of $181 million (8.5%) below the prior year costs. This decrease was primarily due to a $108 million decrease related to lower KWHs generated as a result of closer to normal weather in 2011 compared to 2010, a reduction in unit power energy sales, and a $56 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power expenses were $2.1 billion in 2010. The increase over the prior year costs was not material.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. In 2011, purchased power from non-affiliates was $73 million. The increase from prior year costs was not material. In 2010, purchased power from non-affiliates decreased $16 million (18.2%) due to a 22.4% decrease in the amount of energy purchased, partially offset by a 6.7% increase in the average cost per KWH. In 2011 and 2010, purchased power from affiliates decreased $10 million and $11 million, respectively. The decreases from prior year costs were not material.

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.

Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses decreased $156 million (11.0%) due to a $79 million decrease in transmission and distribution expenses related to vegetation management, reliability projects, and a reduction in accruals to the natural disaster reserve (NDR). Nuclear production expenses decreased $33 million primarily related to a change to the nuclear maintenance outage accounting process associated with the routine refueling activities, as approved by the Alabama PSC in August 2010. As a result, no nuclear maintenance outage expenses were recognized in 2011, reducing nuclear production expense by approximately $50 million compared to 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. In addition, the decrease in nuclear production expenses were partially offset by an increase in operations costs related to increases in labor. Administrative and general expenses decreased $28 million primarily related to injuries and damages expenses, affiliated service companies' expenses, and property insurance.

In 2010, other operations and maintenance expenses increased $207 million (17.1%) due to a $60 million increase in steam production expenses related to planned outage maintenance, environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and maintenance costs related to increases in labor and materials expenses, a $59 million increase in administrative and general expenses related to affiliated service companies' expenses, injuries and damages expenses, labor, and other general expenses, partially offset by a reduction in employee medical and other benefit-related expenses, a $57 million increase in transmission and distribution expenses related to vegetation management and an additional accrual to the NDR, and a $21 million increase in nuclear production expense related to scheduled outage costs and maintenance costs related to increases in labor.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.

Depreciation and Amortization

Depreciation and amortization increased $31 million (5.1%) in 2011 and $61 million (11.2%) in 2010, primarily due to additions to property, plant, and equipment related to environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7 million (2.1%) in 2011 and $10 million (3.1%) in 2010. The increases in 2011 and 2010 were primarily due to increases in state and municipal public utility license tax bases and an increase in local use tax.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $14 million (38.9%) in 2011 primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller. AFUDC equity decreased $43 million (54.4%) in 2010 from 2009 primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller partially offset by an increase in nuclear production projects. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Income Taxes

Income taxes increased $15 million (3.2%) in 2011 primarily due to higher pre-tax income, an increase in the tax expense associated with a decrease in AFUDC equity, and prior year tax return actualization.

Income taxes increased $79 million (20.6%) in 2010, primarily due to higher pre-tax income as compared to 2009, an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid, and an increase in the tax expense associated with a decrease in AFUDC equity and a decrease in the Internal Revenue Code of 1986, as amended, Section 199 production activities deduction.

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. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" and "FERC Matters" 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 primary 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 amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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 five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power Company (Georgia 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 Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company 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 the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power Company (Mississippi Power). On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted the Company 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 $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $34 million, $130 million, and $526 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 $86 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$22	$20	$44

The environmental costs that are known and estimable at this time are included in the Company's approved construction program and capital expenditures 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.

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.

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 $1.2 billion 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 $630 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 $170	Up to $350	Up to $650
Proposed water and coal combustion byproducts rules	Up to $5	Up to $150	Up to $475
Total potential incremental environmental compliance investments	**Up to $175**	**Up to $500**	**Up to $1,125**

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.

As of December 31, 2011, the Company had total generating capacity of approximately 12,222 megawatts (MWs), of which 6,579 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 the seven largest coal units making up 4,812 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 Georgia 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 Georgia Power through a power purchase agreement (PPA). See Note 4 to the Company's financial statements for additional information. 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.

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 $2.7 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.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. On April 6, 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by the Company, including units co-owned by Mississippi Power. The Company filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves the Company's appeal in its favor, the EPA's rescission will continue to affect the Company's operations.

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.

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.

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, and the MATS 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.

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 above, 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 six 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 State of Alabama 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 above, 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.

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. 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 45 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 continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions. The Company is actively pursuing energy from resources with lower greenhouse gas emissions. The Company has entered into PPAs for the purchase of approximately 400 MWs of energy from renewable sources, including wind energy, some of which is pending regulatory approval.

FERC Matters

In 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued annual licenses for the Coosa River developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before FERC, in March 2010, the FERC issued a new 30 year license to the Company for the Warrior River developments. In April 2010, the Smith Lake Improvement and Stakeholder Association filed a request for rehearing of the FERC order granting the new Warrior license. In May 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues raised in the request. The ultimate outcome of this matter cannot be determined at this time.

In 2006, the Company initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. On June 8, 2011, the Company filed an application with the FERC to relicense the Martin Dam Project. The ultimate outcome of this matter cannot be determined at this time.

In 2010, the Company initiated the process of developing an application to relicense the Holt Hydroelectric Project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed no later than August 31, 2013.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot be determined at this time.

PSC Matters

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, the Company agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, the Company had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that the Company leave in effect for 2012 the factors associated with the Company's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, the Company had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations – General" herein for additional information regarding environmental regulations.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. On December 6, 2011, the Alabama PSC issued a consent order that the Company leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, the Company had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Income Tax Matters

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 $75 million and $90 million in 2012.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded non-cash pre-tax pension income of approximately $21 million, $19 million, and $24 million in 2011, 2010, and 2009, respectively. Postretirement benefit costs for the Company were $11 million, $14 million, and $19 million in 2011, 2010, and 2009, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. 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 Nuclear Regulatory Commission (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 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 Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies 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.

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 $6 million or less change in total benefit expense and an $81 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 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 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's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities in 2011 totaled $2.1 billion, an increase of $675 million as compared to 2010. The increase in cash provided from operating activities was primarily due to accrued taxes and deferred income taxes related to benefits associated with bonus depreciation, other current liabilities, accounts payable, and depreciation and amortization. Net cash provided from operating activities in 2010 totaled $1.4 billion, a decrease of $231 million as compared to 2009. The decrease in cash provided from operating activities was primarily due to receivables and other current liabilities related to less cash collections of regulatory clause revenues when compared to the prior year. This is partially offset by an increase in deferred income taxes related to bonus depreciation.

Net cash used for investing activities totaled $1.0 billion for 2011 and 2010 and $1.2 billion for 2009 primarily due to gross property additions to utility plant of $1.0 billion, $0.9 billion, and $1.2 billion for 2011, 2010, and 2009, respectively. These additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.

Net cash used for financing activities totaled $869 million in 2011 primarily due to issuances, redemptions, and a maturity of debt securities and payment of higher common stock dividends to Southern Company. Net cash used for financing activities totaled $600 million in 2010 primarily due to the payment of common stock dividends. Net cash used for financing activities totaled $35 million in 2009 primarily due to the redemption of debt securities and dividends paid in excess of debt issuances and cash raised from common stock sales. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2011 include increases in cash and cash equivalents and accumulated deferred income taxes of $190 million and $510 million, respectively, related to additional bonus depreciation, $304 million in property, plant, and equipment associated with routine property additions and nuclear fuel, and $319 million in other regulatory assets, deferred, partially offset by decreases of $134 million in prepaid expenses related to income taxes and $198 million in prepaid pension cost.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.9% in 2011 and 44.0% in 2010. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

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

At December 31, 2011, the Company had approximately $344 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires[a]						Executable Term-Loans	
2012	2013	2014	2016	Total	Unused	One Year	Two Years
(in millions)							
$121	$35	$350	$800	$1,306	$1,306	$51	$-

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

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.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. At December 31, 2011, the Company had $794 million of outstanding 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 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	$ -	-%	$20	0.22%	$255
December 31, 2010:					
Commercial paper	$ -	-%	$ 7	0.22%	$135

(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

In February 2011, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

In March 2011, the Company issued $250 million aggregate principal amount of Series 2011A 5.50% Senior Notes due March 15, 2041. The proceeds were used for general corporate purposes, including the Company's continuous construction program. The Company settled $200 million of interest rate hedges related to the Series 2011A 5.50% Senior Note issuance at a gain of approximately $4 million. The gain is being amortized to interest expense, in earnings, over 10 years.

In May 2011, the Company issued $200 million aggregate principal amount of Series 2011B 3.950% Senior Notes due June 1, 2021 and $250 million aggregate principal amount of Series 2011C 5.200% Senior Notes due June 1, 2041. The net proceeds were used by the Company for the redemption of $100 million aggregate principal amount of the Series GG 5 7/8% Senior Notes due February 1, 2046, $200 million aggregate principal amount of the Series II 5.875% Senior Notes due March 15, 2046, and $150 million aggregate principal amount of the Series JJ 6.375% Senior Notes due June 15, 2046.

In August 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $300 million.

In September 2011, the Company redeemed approximately $4 million of The Industrial Development Board of the Town of Wilsonville Solid Waste Disposal Revenue Bonds (Plant Gaston), Series 2008.

In November 2011, the Company redeemed approximately $100 million aggregate principal amount of Series EE 5.75% Senior Notes due January 15, 2036.

Subsequent to December 31, 2011, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program. In November 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes in anticipation of this debt issuance. The notional amount of the swaps totaled $100 million and settled subsequent to December 31, 2011, at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

Subsequent to December 31, 2011, the Company announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012. Also, the Company announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

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 below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $311 million. 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 $1 million of long-term variable interest rate exposure that has not been hedged at January 1, 2012 was .84%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 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 retail fuel hedging program implemented per the guidelines of the Alabama PSC.

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

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	**$(38)**	$(44)
Contracts realized or settled	**37**	61
Current period changes[a]	**(47)**	(55)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(48)**	$(38)

(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 a decrease of $10 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 38.9 million mmBtu with a weighted average swap contract cost approximately $1.45 per mmBtu above market prices, compared to a net hedge volume of 33.9 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $1.14 per mmBtu above market prices. All the natural gas hedge gains and losses are recovered through the Company's fuel cost recovery clause.

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. 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 clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. 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	(48)	(36)	(12)
Level 3	-	-	-
Fair value of contracts outstanding at end of period	$(48)	$(36)	$(12)

The Company is exposed to market price risk in the event of nonperformance by counterparties to 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 Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending $554 million on Plant Farley (including nuclear fuel), $932 million on distribution facilities, and $597 million on transmission additions. These base level capital investment 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. 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.

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 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, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$915	$936	$1,102
Existing environmental statutes and regulations	22	20	44
Total construction program base level capital investment	**$937**	**$956**	**$1,146**
Potential incremental environmental compliance investments:			
MATS rule	Up to $170	Up to $350	Up to$650
Proposed water and coal combustion byproducts rules	Up to $5	Up to $150	Up to $475
Total potential incremental environmental compliance investments	**Up to $175**	**Up to $500**	**Up to $1,125**

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; Alabama 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.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." In addition to the funds required for the Company's construction program, approximately $750 million will be required by the end of 2014 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

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

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	$ 500	$ 250	$ 254	$ 5,128	$ -	$ 6,132
Interest	279	495	481	3,812	-	5,067
Preferred and preference stock dividends[(b)]	39	79	79	-	-	197
Energy-related derivative obligations[(c)]	36	12	-	-	-	48
Interest rate derivative obligations[(c)]	18	-	-	-	-	18
Operating leases	21	24	13	2	-	60
Unrecognized tax benefits and interest[(d)]	6	-	-	-	28	34
Purchase commitments[(e)] –						
Capital[(f)]	755	1,818	-	-	-	2,573
Limestone[(g)]	16	34	24	38	-	112
Coal	1,347	1,881	430	463	-	4,121
Nuclear fuel	96	73	64	212	-	445
Natural gas[(h)]	246	411	284	124	-	1,065
Purchased power	31	83	93	419	-	626
Long-term service agreements[(i)]	24	35	36	-	-	95
Pension and other postretirement benefit plans[(j)]	20	33	-	-	-	53
Total	$3,434	$5,228	$1,758	$10,198	$28	$20,646

(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.

(b) Preferred and preference stock do not mature; therefore, amounts are provided 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 $28 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 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 $1.3 billion, $1.4 billion, and $1.2 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 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 $175 million, up to $500 million, and up to $1.1 billion 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 certain of 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) Long-term service agreements include price escalation based on inflation indices.

(j) 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, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, 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, 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, including FERC matters, 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 actions relating to fuel and other cost recovery mechanisms;
- 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;
- 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
Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$4,972**	$5,076	$4,497
Wholesale revenues, non-affiliates	**287**	465	620
Wholesale revenues, affiliates	**244**	236	237
Other revenues	**199**	199	175
Total operating revenues	**5,702**	5,976	5,529
Operating Expenses:			
Fuel	**1,679**	1,851	1,824
Purchased power, non-affiliates	**73**	72	88
Purchased power, affiliates	**198**	208	219
Other operations and maintenance	**1,262**	1,418	1,211
Depreciation and amortization	**637**	606	545
Taxes other than income taxes	**339**	332	322
Total operating expenses	**4,188**	4,487	4,209
Operating Income	**1,514**	1,489	1,320
Other Income and (Expense):			
Allowance for equity funds used during construction	**22**	36	79
Interest income	**18**	17	17
Interest expense, net of amounts capitalized	**(299)**	(303)	(298)
Other income (expense), net	**(30)**	(30)	(25)
Total other income and (expense)	**(289)**	(280)	(227)
Earnings Before Income Taxes	**1,225**	1,209	1,093
Income taxes	**478**	463	384
Net Income	**747**	746	709
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 708**	$ 707	$ 670

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$708**	$707	$670
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(5), $-, and $(2), respectively	**(9)**	-	(3)
Reclassification adjustment for amounts included in net income, net of tax of $(1), $(1), and $5, respectively	**(2)**	(2)	8
Total other comprehensive income (loss)	**(11)**	(2)	5
Comprehensive Income	**$697**	$705	$675

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

Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Net income	**$ 747**	$ 746	$ 709
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**749**	694	637
Deferred income taxes	**459**	410	(66)
Allowance for equity funds used during construction	**(22)**	(36)	(79)
Pension, postretirement, and other employee benefits	**(32)**	(15)	(8)
Pension and postretirement funding	**(9)**	(55)	(17)
Stock based compensation expense	**6**	5	4
Natural disaster reserve	**34**	52	55
Other, net	**(41)**	(27)	8
Changes in certain current assets and liabilities --			
-Receivables	**18**	(29)	310
-Fossil fuel stock	**47**	(1)	(77)
-Materials and supplies	**(33)**	(20)	(22)
-Other current assets	**(6)**	(4)	(16)
-Accounts payable	**11**	(54)	(19)
-Accrued taxes	**157**	(140)	24
-Accrued compensation	**(12)**	28	(32)
-Other current liabilities	**(25)**	(181)	193
Net cash provided from operating activities	**2,048**	1,373	1,604
Investing Activities:			
Property additions	**(977)**	(903)	(1,234)
Investment in restricted cash from pollution control bonds	**4**	-	(6)
Distribution of restricted cash from pollution control bonds	**13**	18	49
Nuclear decommissioning trust fund purchases	**(350)**	(237)	(245)
Nuclear decommissioning trust fund sales	**349**	236	244
Cost of removal net of salvage	**(28)**	(44)	(38)
Change in construction payables	**(9)**	(45)	26
Other investing activities	**9**	(12)	(25)
Net cash used for investing activities	**(989)**	(987)	(1,229)
Financing Activities:			
Increase (decrease) in notes payable, net	**-**	-	(25)
Proceeds --			
Common stock issued to parent	**-**	-	203
Capital contributions from parent company	**12**	28	24
Pollution control revenue bonds	**-**	-	79
Senior notes issuances	**700**	250	500
Redemptions --			
Pollution control revenue bonds	**(4)**	-	-
Senior notes	**(750)**	(250)	(250)
Payment of preferred and preference stock dividends	**(39)**	(39)	(39)
Payment of common stock dividends	**(774)**	(586)	(523)
Other financing activities	**(14)**	(3)	(4)
Net cash used for financing activities	**(869)**	(600)	(35)
Net Change in Cash and Cash Equivalents	**190**	(214)	340
Cash and Cash Equivalents at Beginning of Year	**154**	368	28
Cash and Cash Equivalents at End of Year	**$ 344**	$ 154	$ 368
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $9, $14 and $33 capitalized, respectively)	**$286**	$288	$255
Income taxes (net of refunds)	**(139)**	188	426
Noncash transactions - accrued property additions at year-end	**19**	28	74

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

BALANCE SHEETS

At December 31, 2011 and 2010

Alabama Power Company 2011 Annual Report

Assets	2011	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 344	$ 154
Restricted cash	1	18
Receivables --		
Customer accounts receivable	332	362
Unbilled revenues	126	153
Under recovered regulatory clause revenues	-	5
Other accounts and notes receivable	35	35
Affiliated companies	79	57
Accumulated provision for uncollectible accounts	(10)	(10)
Fossil fuel stock, at average cost	344	391
Materials and supplies, at average cost	375	346
Vacation pay	59	55
Prepaid expenses	74	208
Other regulatory assets, current	44	38
Other current assets	11	10
Total current assets	1,814	1,822
Property, Plant, and Equipment:		
In service	20,809	19,966
Less accumulated provision for depreciation	7,344	6,931
Plant in service, net of depreciation	13,465	13,035
Nuclear fuel, at amortized cost	330	283
Construction work in progress	374	547
Total property, plant, and equipment	14,169	13,865
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	62	64
Nuclear decommissioning trusts, at fair value	540	552
Miscellaneous property and investments	73	71
Total other property and investments	675	687
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	532	488
Prepaid pension costs	59	257
Deferred under recovered regulatory clause revenues	48	4
Other regulatory assets, deferred	994	675
Other deferred charges and assets	186	196
Total deferred charges and other assets	1,819	1,620
Total Assets	$18,477	$17,994

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

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

Liabilities and Stockholder's Equity	**2011**	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 500**	$ 200
Accounts payable --		
Affiliated	**203**	210
Other	**322**	273
Customer deposits	**85**	86
Accrued taxes --		
Accrued income taxes	**32**	2
Other accrued taxes	**34**	32
Accrued interest	**63**	63
Accrued vacation pay	**48**	45
Accrued compensation	**95**	99
Liabilities from risk management activities	**54**	31
Over recovered regulatory clause revenues	**-**	22
Other regulatory liabilities, current	**18**	-
Other current liabilities	**38**	41
Total current liabilities	**1,492**	1,104
Long-Term Debt (See accompanying statements)	**5,632**	5,987
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,257**	2,747
Deferred credits related to income taxes	**83**	85
Accumulated deferred investment tax credits	**149**	157
Employee benefit obligations	**343**	311
Asset retirement obligations	**553**	520
Other cost of removal obligations	**703**	701
Other regulatory liabilities, deferred	**156**	217
Other deferred credits and liabilities	**82**	87
Total deferred credits and other liabilities	**5,326**	4,825
Total Liabilities	**12,450**	11,916
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,342**	5,393
Total Liabilities and Stockholder's Equity	**$18,477**	$17,994
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
Alabama Power Company 2011 Annual Report

	2011	2010	2011	2010
		(in millions)		*(percent of total)*
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
Variable rate (3.68% at 1/1/12) due 2042	**$ 206**	$ 206		
Long-term notes payable --				
5.10% due 2011	**-**	200		
4.85% due 2012	**500**	500		
5.80% due 2013	**250**	250		
5.20% due 2016	**200**	200		
3.375% to 6.375% due 2017-2047	**3,825**	3,675		
Total long-term notes payable	**4,775**	4,825		
Other long-term debt --				
Pollution control revenue bonds --				
0.75% to 5.00% due 2034	**367**	367		
Variable rate (0.07% at 1/1/12) due 2015	**54**	54		
Variable rates (0.03% to 0.17% at 1/1/12) due 2017-2038	**730**	734		
Total other long-term debt	**1,151**	1,155		
Unamortized debt premium (discount), net	**-**	1		
Total long-term debt (annual interest requirement -- $279 million)	**6,132**	6,187		
Less amount due within one year	**500**	200		
Long-term debt excluding amount due within one year	**5,632**	5,987	**48.4%**	49.6%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2011 and 2010
Alabama Power Company 2011 Annual Report

	2011	2010	2011	2010
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**48**	48		
$1 par value -- 5.20% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value				
(annual dividend requirement -- $18 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.9**	2.8
Preference Stock:				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63% to 6.50%				
- 14,000,000 shares				
(non-cumulative) $25 stated value				
(annual dividend requirement -- $21 million)	**343**	343	**2.9**	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,182**	2,156		
Retained earnings	**1,956**	2,022		
Accumulated other comprehensive income (loss)	**(18)**	(7)		
Total common stockholder's equity	**5,342**	5,393	**45.8**	44.7
Total Capitalization	**$11,659**	$12,065	**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
Alabama 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	25	$1,019	$2,091	$1,754	$(10)	$4,854
Net income after dividends on preferred and preference stock	-	-	-	670	-	670
Issuance of common stock	5	203	-	-	-	203
Capital contributions from parent company	-	-	28	-	-	28
Other comprehensive income (loss)	-	-	-	-	5	5
Cash dividends on common stock	-	-	-	(523)	-	(523)
Other	1	-	-	-	-	-
Balance at December 31, 2009	31	1,222	2,119	1,901	(5)	5,237
Net income after dividends on preferred and preference stock	-	-	-	707	-	707
Issuance of common stock	-	-	-	-	-	-
Capital contributions from parent company	-	-	37	-	-	37
Other comprehensive income (loss)	-	-	-	-	(2)	(2)
Cash dividends on common stock	-	-	-	(586)	-	(586)
Balance at December 31, 2010	**31**	**1,222**	**2,156**	**2,022**	**(7)**	**5,393**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**708**	**-**	**708**
Capital contributions from parent company	**-**	**-**	**26**	**-**	**-**	**26**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**(11)**	**(11)**
Cash dividends on common stock	**-**	**-**	**-**	**(774)**	**-**	**(774)**
Balance at December 31, 2011	**31**	**$1,222**	**$2,182**	**$1,956**	**$(18)**	**$5,342**

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of 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, Georgia Power Company (Georgia 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 and wholesale customers within its traditional service area located in the State of Alabama in addition 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 Farley.

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 Alabama 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 $347 million, $371 million, and $325 million during 2011, 2010, and 2009, respectively. 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 $215 million, $218 million, and $183 million during 2011, 2010, and 2009, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $12 million in 2011, $11 million in 2010, and $10 million in 2009. See Note 4 for additional information.

Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2010 and 2009 totaled $15 million and $62 million, respectively. The Company also provided the fuel, at cost, associated with the PPA totaling $21 million and $63 million in 2010 and 2009, respectively. Due to the expiration of the Plant Harris PPA in May 2010, no purchased power costs or fuel costs were recognized in 2011. Additionally, the Company recorded no prepaid capacity expenses in 2011 or 2010 but recorded $8.3 million in 2009 which is included in other deferred charges and other assets in the balance sheets at December 31, 2009. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $85 million over the next three years. The Company expects to recover a majority of these costs through a tariff from Gulf Power over the next eleven years.

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, and 2009.

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

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

Regulatory Assets and Liabilities

The Company is subject to the provisions of 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)		
Deferred income tax charges	**$ 532**	$ 488	(a, k)
Loss on reacquired debt	**84**	74	(b)
Vacation pay	**59**	55	(c, j)
Under/(over) recovered regulatory clause revenues	**47**	(13)	(d)
Fuel-hedging (realized and unrealized) losses	**48**	39	(e)
Other assets	**46**	30	(f)
Asset retirement obligations	**(35)**	(77)	(a)
Other cost of removal obligations	**(703)**	(701)	(a)
Deferred income tax credits	**(83)**	(85)	(a)
Fuel-hedging (realized and unrealized) gains	**(1)**	(1)	(e)
Mine reclamation and remediation	**(8)**	(10)	(g)
Nuclear outage	**38**	-	(d)
Natural disaster reserve	**(110)**	(127)	(h)
Other liabilities	**(20)**	(3)	(d)
Retiree benefit plans	**822**	569	(i, j)
Total assets (liabilities), net	**$ 716**	$ 238	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

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

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding five years.

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

(f) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 and Note 5 for additional information.

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

(k) Included in the deferred income tax charges is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years. See Note 5 for additional information.

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 rates. See Note 3 under "Retail Regulatory Matters" for additional information.

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, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally 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 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 interest capitalized and cost of equity 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	**$10,982**	$10,598
Transmission	**2,998**	2,826
Distribution	**5,517**	5,267
General	**1,300**	1,262
Plant acquisition adjustment	**12**	12
Total plant in service	**$20,809**	$19,965

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

In August 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18 month cycle ended in December 2010 and to begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known.

During 2011, the Company deferred $38 million of nuclear outage expenses associated with the fall 2011 outage and began the first 18-month amortization cycle for expenses in January 2012. The deferred nuclear outage expense balance of $38 million is included in the balance sheet as a regulatory asset. The second amortization cycle will begin in July 2012 for expenses associated with the spring 2012 outage.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2011, 3.3% in 2010, and 3.2% in 2009. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation 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.

During 2011, a depreciation study was completed based on information as of December 31, 2009. The study was approved by the FERC in October 2011 and was also provided to the Alabama PSC. The change in depreciation expense for 2012 associated with the approved rates is immaterial.

Asset Retirement Obligations and Other Costs of Removal

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

The liability for asset retirement obligations primarily relates to the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized 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, as ordered by the Alabama PSC, and are reflected in the balance sheets. 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	**$520**	$491
Liabilities incurred	**-**	-
Liabilities settled	**(2)**	(2)
Accretion	**35**	33
Cash flow revisions [(a)]	**-**	(2)
Balance at end of year	**$553**	$520

(a) Updated based on results from the 2009 Nuclear Interim Study

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 Alabama 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.

At December 31, 2011, investment securities in the Funds totaled $539 million consisting of equity securities of $382 million, debt securities of $146 million, and $11 million of other securities. At December 31, 2010, investment securities in the Funds totaled $552 million consisting of equity securities of $406 million, debt securities of $139 million, and $7 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $349 million, $236 million, and $244 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 $6 million, of which $41 million related to realized gains and $51 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 $65 million, of which $31 million 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 $96 million, of which $80 million 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.

Amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan 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.
At December 31, 2011, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$540
Internal reserves	23
Total	$563

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065
	(in millions)
Site study costs:	
Radiated structures	$1,060
Non-radiated structures	72
Total site study costs	$1,132

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

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be conducted in 2013.

As a result of license extensions, amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements.

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 regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.2% in 2011, 9.4% in 2010, and 9.2% in 2009. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 3.9% in 2011, 6.3% in 2010, and 14.9% in 2009.

Impairment of Long-Lived Assets and Intangibles

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

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the Natural Disaster Reserve (NDR) when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve. See Note 3 under "Natural Disaster Reserve" herein 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 Alabama 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 Alabama 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 Entity

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in the Company consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

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 Alabama PSC and the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to total approximately $8 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	**4.88**	5.41	5.84
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	**7.39**	7.43	7.52

*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	$32	$(27)
Service and interest costs	2	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.8 billion at December 31, 2011 and $1.7 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	**$1,779**	$1,675
Service cost	**43**	41
Interest cost	**96**	97
Benefits paid	**(88)**	(81)
Actuarial loss (gain)	**102**	47
Balance at end of year	**1,932**	1,779
Change in plan assets		
Fair value of plan assets at beginning of year	**1,933**	1,712
Actual return (loss) on plan assets	**32**	258
Employer contributions	**8**	44
Benefits paid	**(88)**	(81)
Fair value of plan assets at end of year	**1,885**	1,933
(Accrued liability) prepaid pension asset	**$ (47)**	$ 154

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $1.8 billion and $106 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	**$ 59**	$257
Other regulatory assets, deferred	**727**	497
Other current liabilities	**(7)**	(7)
Employee benefit obligations	**(99)**	(96)

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	**$ 33**	$ 41	**$ 7**
Net (gain) loss	**694**	456	**23**
Other regulatory assets, deferred	**$727**	$497	

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	$549
Net (gain) loss	(42)
Change in prior service costs	1
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain (loss)	(2)
Total reclassification adjustments	(11)
Total change	(52)
Balance at December 31, 2010	$497
Net (gain) loss	**243**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of prior service costs	**(9)**
Amortization of net gain (loss)	**(4)**
Total reclassification adjustments	**(13)**
Total change	**230**
Balance at December 31, 2011	**$727**

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

	2011	2010	2009
		(in millions)	
Service cost	**$ 43**	$ 41	$ 34
Interest cost	**96**	97	96
Expected return on plan assets	**(173)**	(168)	(164)
Recognized net (gain) loss	**4**	2	1
Net amortization	**9**	9	9
Net periodic pension cost (income)	**$ (21)**	$ (19)	$ (24)

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	$ 95
2013	99
2014	102
2015	106
2016	110
2017 to 2021	604

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	**$ 454**	$ 461
Service cost	**5**	6
Interest cost	**24**	26
Benefits paid	**(27)**	(26)
Actuarial loss (gain)	**11**	(16)
Plan amendments	**-**	-
Retiree drug subsidy	**3**	3
Balance at end of year	**470**	454
Change in plan assets		
Fair value of plan assets at beginning of year	**323**	295
Actual return (loss) on plan assets	**5**	35
Employer contributions	**11**	16
Benefits paid	**(24)**	(23)
Fair value of plan assets at end of year	**315**	323
Accrued liability	**$(155)**	$(131)

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	**$ 96**	$ 72
Employee benefit obligations	**(155)**	(131)

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	**$ 26**	$ 30	**$ 4**
Net (gain) loss	**68**	37	**-**
Transition obligation	**2**	5	**2**
Regulatory assets	**$ 96**	$ 72	

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	$108
Net (gain) loss	(29)
Change in prior service costs/transition obligation	-
Reclassification adjustments:	
Amortization of transition obligation	(3)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	-
Total reclassification adjustments	(7)
Total change	(36)
Balance at December 31, 2010	$ 72
Net (gain) loss	**31**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(3)**
Amortization of prior service costs	**(4)**
Amortization of net gain (loss)	**-**
Total reclassification adjustments	**(7)**
Total change	**24**
Balance at December 31, 2011	**$ 96**

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

	2011	2010	2009
		(in millions)	
Service cost	**$ 5**	$ 6	$ 6
Interest cost	**24**	26	29
Expected return on plan assets	**(25)**	(25)	(24)
Net amortization	**7**	7	8
Net postretirement cost	**$ 11**	$ 14	$ 19

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	$ 30	$ (3)	$ 27
2013	32	(4)	28
2014	34	(4)	30
2015	35	(4)	31
2016	36	(5)	31
2017 to 2021	185	(28)	157

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	46%	**41%**	41%
International equity	11	**14**	16
Domestic fixed income	35	**38**	36
Special situations	1	**-**	-
Real estate investments	4	**4**	4
Private equity	3	**3**	3
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 presented in the tables below based on the nature of the investment.

As of December 31, 2011:	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*	$320	$148	$ -	$ 468
International equity*	329	94	-	423
Fixed income:				
U.S. Treasury, government, and agency bonds	-	120	-	120
Mortgage- and asset-backed securities	-	37	-	37
Corporate bonds	-	232	1	233
Pooled funds	-	105	-	105
Cash equivalents and other	-	39	-	39
Real estate investments	61	-	217	278
Private equity	-	-	161	161
Total	$710	$775	$379	$1,864

*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*	$358	$144	$ -	$ 502
International equity*	361	125	-	486
Fixed income:				
U.S. Treasury, government, and agency bonds	-	86	-	86
Mortgage- and asset-backed securities	-	70	-	70
Corporate bonds	-	168	1	169
Pooled funds	-	57	-	57
Cash equivalents and other	1	135	-	136
Real estate investments	52	-	191	243
Private equity	-	-	180	180
Total	$772	$785	$372	$1,929

*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	**$191**	**$180**	$166	$169
Actual return on investments:				
Related to investments held at year end	**16**	**(3)**	14	9
Related to investments sold during the year	**6**	**9**	3	3
Total return on investments	**22**	**6**	17	12
Purchases, sales, and settlements	**4**	**(25)**	8	(1)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$217**	**$161**	$191	$180

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. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	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*	$57	$ 8	$ -	$ 65
International equity*	17	5	-	22
Fixed income:				
U.S. Treasury, government, and agency bonds	-	9	-	9
Mortgage- and asset-backed securities	-	2	-	2
Corporate bonds	-	12	-	12
Pooled funds	-	5	-	5
Cash equivalents and other	-	19	-	19
Trust-owned life insurance	-	160	-	160
Real estate investments	4	-	11	15
Private equity	-	-	8	8
Total	$78	$220	$19	$317

*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*	$62	$ 7	$ -	$ 69
International equity*	19	6	-	25
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5	-	5
Mortgage- and asset-backed securities	-	4	-	4
Corporate bonds	-	9	-	9
Pooled funds	-	3	-	3
Cash equivalents and other	-	24	-	24
Trust-owned life insurance	-	159	-	159
Real estate investments	3	-	10	13
Private equity	-	-	9	9
Total	$84	$217	$19	$320

*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		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 10**	**$9**	$ 9	$10
Actual return on investments:				
Related to investments held at year end	**1**	**-**	1	-
Related to investments sold during the year	**-**	**-**	-	-
Total return on investments	**1**	**-**	1	-
Purchases, sales, and settlements	**-**	**(1)**	-	(1)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$11**	**$ 8**	$10	$ 9

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 $18 million, $18 million, and $19 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 five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia 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 Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company 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 the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted the Company 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 could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

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

In 2007, the U.S. Court of Federal Claims awarded the Company approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley 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 the Company. On July 12, 2011, the court entered final judgment in favor of the Company and awarded the Company approximately $17 million. In April 2012, the award will be credited to cost of service for the benefit of customers.

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 the second claim. The final outcome of these matters cannot be determined at this time.

An on-site dry spent fuel storage facility at Plant Farley is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, the Company agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010, of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, the Company had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that the Company leave in effect for 2012 the factors associated with the Company's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, the Company had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under the Company's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt-hour (KWH). On December 6, 2011, the Alabama PSC issued a consent order that the Company leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, the Company had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia 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 $142 million in 2011, $101 million in 2010, and $82 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.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2011, the capitalization of SEGCO consisted of $87 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. SEGCO paid dividends of $15 million in 2011, $5 million in 2010, and none in 2009, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2011 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Amount of Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00% (1)	$ 148	$ 78
Plant Miller				
Units 1 and 2	1,320	91.84% (2)	1,389	510

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

At December 31, 2011, the Company's portion of Plant Miller construction work in progress was $7.4 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income 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. In addition, the Company files a separate company income tax return for the State of Tennessee. 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	**$ 20**	$ 52	$374
Deferred	**377**	333	(41)
	$397	$385	$333
State –			
Current	**$ (1)**	$ 1	$ 76
Deferred	**82**	77	(25)
	81	78	51
Total	**$478**	$463	$384

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	**$2,820**	$2,415
Property basis differences	**439**	396
Premium on reacquired debt	**33**	31
Pension and other benefits	**217**	210
Fuel clause under recovered	**26**	10
Regulatory assets associated with employee benefit obligations	**343**	239
Regulatory assets associated with asset retirement obligations	**233**	220
Other	**94**	85
Total	**4,205**	3,606
Deferred tax assets:		
Federal effect of state deferred taxes	**186**	177
State effect of federal deferred taxes	**-**	50
Unbilled revenue	**38**	41
Storm reserve	**38**	41
Pension and other benefits	**373**	264
Other comprehensive losses	**14**	8
Asset retirement obligations	**233**	220
Other	**97**	87
Total	**979**	888
Total deferred tax liabilities, net	**3,226**	2,718
Portion included in current assets (liabilities), net	**31**	29
Accumulated deferred income taxes	**$3,257**	$2,747

At December 31, 2011, the Company's tax-related regulatory assets to be recovered from customers were $532 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 $21 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 will amortize the regulatory asset to income tax expense over the average remaining service period which may range up to 15 years, as approved by the Alabama PSC.

At December 31, 2011, the Company's tax-related regulatory liabilities to be credited to customers were $83 million. These liabilities are attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2011, 2010, and 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	**4.3**	4.2	3.0
Non-deductible book depreciation	**0.8**	0.8	0.8
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.2)
AFUDC-equity	**(0.6)**	(1.0)	(2.5)
Production activities deduction	**-**	-	(0.8)
Other	**(0.4)**	(0.6)	(0.2)
Effective income tax rate	**39.0%**	38.3%	35.1%

State income tax, net of federal deduction in 2011, was not materially different when compared to 2010. In 2010, state income tax, net of federal deduction increased due to a decrease in the state deduction for federal income taxes paid, which is a result of increased bonus depreciation and pension contributions.

The tax benefit of AFUDC-equity decreased in 2011 and 2010 from prior years due to a decrease in AFUDC, resulting from the completion of construction projects related to environmental mandates at generating facilities. See Note 1 under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $11 million, resulting in a balance of $32 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	**$43**	$ 6	$3
Tax positions from current periods	**6**	6	2
Tax positions from prior periods	**(17)**	31	1
Reductions due to settlements	**-**	-	-
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$32**	$43	$6

The tax positions from current periods for 2011 relate primarily to the tax accounting method change for repairs-generation assets. The tax positions decrease from prior periods for 2011 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	**$ 5**	$ 6	$6
Tax positions not impacting the effective tax rate	**27**	37	-
Balance of unrecognized tax benefits	**$32**	$43	$6

The tax positions impacting the effective tax rate for 2011 primarily relate to the production activities deduction tax position. 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	**$1.5**	$0.3	$0.3
Interest reclassified due to settlements	**-**	-	-
Interest accrued during the year	**0.4**	1.2	-
Balance at end of year	**$1.9**	$1.5	$0.3

The Company classifies interest on tax uncertainties as interest expense. 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 $141 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 an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary 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 as of December 31, 2011 and December 31, 2010, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2011 and 2010, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entity" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2011 and 2010, the Company had scheduled maturities of senior notes due within one year totaling $500 million and $200 million, respectively.

Maturities of senior notes and pollution control revenue bonds through 2016 applicable to total long-term debt are as follows: $500 million in 2012; $250 million in 2013; $54 million in 2015; and $200 million in 2016. There are no scheduled maturities in 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2011. In 2011, the Company redeemed approximately $4 million of The Industrial Development Board of the Town of Wilsonville Solid Waste Disposal Revenue Bonds (Plant Gaston), Series 2008. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2011 and 2010 was $1.2 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Subsequent to December 31, 2011, the Company announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

Senior Notes

The Company issued a total of $700 million of unsecured senior notes in 2011. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program, and to redeem $100 million aggregate principal amount of the Series GG 5-7/8% Senior Notes due February 1, 2046, $200 million aggregate principal amount of the Series II 5.875% Senior Notes due March 15, 2046, $150 million aggregate principal amount of the Series JJ 6.375% Senior Notes due June 15, 2046.

Also during 2011, the Company redeemed approximately $100 million aggregate principal amount of Series EE 5.75% Senior Notes due January 15, 2036.

At both December 31, 2011 and 2010, the Company had $4.8 billion of senior notes outstanding. These senior notes are effectively subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2011.

Subsequent to December 31, 2011, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012.

Preferred, Preference, and Common Stock

In 2011, the Company issued no new shares of preferred stock, preference stock, or common stock.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. Certain series of the Company's preferred stock are subject to redemption at the option of the Company on or after a specified date. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/Stated Capital Per Share	Shares Outstanding	First Call Date	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	*	$103.23
4.72% Preferred Stock	$100	50,000	*	$102.18
4.64% Preferred Stock	$100	60,000	*	$103.14
4.60% Preferred Stock	$100	100,000	*	$104.20
4.52% Preferred Stock	$100	50,000	*	$102.93
4.20% Preferred Stock	$100	135,115	*	$105.00
5.83% Class A Preferred Stock	$ 25	1,520,000	08/1/2008	Stated Capital
5.20% Class A Preferred Stock	$ 25	6,480,000	08/1/2008	Stated Capital
5.30% Class A Preferred Stock	$ 25	4,000,000	04/1/2009	Stated Capital
5.625% Preference Stock	$ 25	6,000,000	01/1/2012	Stated Capital
6.450% Preference Stock	$ 25	6,000,000	*	*
6.500% Preference Stock	$ 25	2,000,000	*	*

* Redemption permitted any time after issuance
**Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; After 10/01/2017: Stated Capital

Dividend Restrictions

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

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2011. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

Expires[a]						Executable Term-Loans	
2012	2013	2014	2016	Total	Unused	One Year	Two Years
		(in millions)					
$121	$35	$350	$800	$1,306	$1,306	$51	$-

(a) No credit arrangements expire in 2015.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. During 2011, the Company remarketed $120 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is $794 million as of December 31, 2011.

Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees average less than ¼ of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2011, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. The cross default provisions are restricted to indebtedness (including guaranteed obligations) of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks.

Details of short-term borrowings 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	$ -	-	$20	0.22%	$255
December 31, 2010:					
Commercial paper	$ -	-	$ 7	0.22%	$135

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

At December 31, 2011, the Company had regulatory approval to have outstanding up to $2.3 billion of short-term borrowings.

7. COMMITMENTS

Construction Program

The approved construction program of the Company is currently estimated to include a base level investment of $0.9 billion for 2012, $1.0 billion for 2013, and $1.1 billion for 2014. Over the next three years, the Company estimates spending $554 million on Plant Farley (including nuclear fuel), $932 million on distribution facilities, and $597 million on transmission additions. These base level investment 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 $22 million, $20 million, and $44 million for 2012, 2013, and 2014, respectively. These base level environmental expenditures do not include potential incremental environmental compliance investments to comply with the EPA's final Mercury and Air Toxics Standards 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; Alabama 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. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

The Company has entered into long-term service agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs provide that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each LTSA.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these LTSAs for facilities owned are currently estimated at $95 million over the remaining life of the LTSAs, which are currently estimated to range up to five years. However, the LTSAs contain various cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

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 2.2 million tons, equating to approximately $112 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $16 million in 2012, $17 million in 2013, $17 million in 2014, $12 million in 2015, and $12 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 and nitrogen oxide 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	$ 246	$1,347	$ 96
2013	237	1,047	30
2014	174	834	43
2015	145	284	43
2016	139	146	21
2017 and thereafter	124	463	212
Total commitments	$1,065	$4,121	$445

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 $95 million in 2011, $79 million in 2010, and $78 million in 2009.

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 entered into various long-term commitments for the purchase of capacity and energy. Total estimated minimum long-term obligations at December 31, 2011 were as follows:

	Commitments
	Non-Affiliated
	(in millions)
2012	$ 31
2013	39
2014	44
2015	46
2016	47
2017 and thereafter	419
Total commitments	$626

Certain PPAs reflected in the table are accounted for as operating leases.

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses amounted to $23 million in 2011, $25 million in 2010, and $27 million in 2009. Of these amounts, $18 million, $20 million, and $20 million for 2011, 2010, and 2009, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR.

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

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2012	$19	$2	$21
2013	15	1	16
2014	7	1	8
2015	6	1	7
2016	5	1	6
2017 and thereafter	2	-	2
Total *	$54	$6	$60

* Total does not include payments related to a non-affiliated PPA that is accounted for as an operating lease. Obligations related to this agreement are included in the above purchased power commitments table.

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. The Company's maximum obligations under these leases are $1 million in 2012, $39 million in 2013, $8 million in 2014, $5 million in 2015, $4 million in 2016, and none in 2017. Upon termination of the leases, the Company has the option to negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2011, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK 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 1,242 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	8,744,984	$32.35
Granted	1,073,781	38.02
Exercised	(2,622,513)	31.15
Cancelled	(4,466)	35.95
Outstanding at December 31, 2011	**7,191,786**	**$33.63**
Exercisable at December 31, 2011	**4,724,956**	**$33.36**

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 $91 million and $61 million, respectively.

As of December 31, 2011, there was $1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $3 million, $3 million, and $4 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $1 million, respectively.

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

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $23 million, $12 million, and $2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $9 million, $4 million, and $1 million for the years ended December 31, 2011, 2010, and 2009, respectively.

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 151,802. During 2011, 142,822 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 6,904 performance share units were forfeited resulting in 287,720 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $3 million and $1 million, respectively, with the related tax benefit also recognized in income of $1 million and $1 million, respectively. As of December 31, 2011, there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley 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 is $235 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 $2.3 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $43 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:				
Nuclear decommissioning trusts:[(a)]				
Domestic equity	$253	$57	$-	$310
Foreign equity	24	48	-	72
U.S. Treasury and government agency securities	17	8	-	25
Corporate bonds	-	93	-	93
Mortgage and asset backed securities	-	28	-	28
Other investments	-	11	-	11
Cash equivalents and restricted cash	209	-	-	209
Total	$503	$245	$ -	$748
Liabilities:				
Energy-related derivatives	$ -	$ 48	$ -	$ 48
Interest rate derivatives	-	18	-	18
Total	$ -	$ 66	$ -	$ 66

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

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	$ -	$ 2	$ -	$ 2
Nuclear decommissioning trusts:[a]				
Domestic equity	347	59	-	406
U.S. Treasury and government agency securities	20	7	-	27
Corporate bonds	-	82	-	82
Mortgage and asset backed securities	-	30	-	30
Other investments	-	7	-	7
Cash equivalents and restricted cash	109	-	-	109
Total	$476	$187	$ -	$663
Liabilities:				
Energy-related derivatives	$ -	$ 40	$ -	$ 40

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

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, 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, power prices, implied volatility, and London Interbank Offered Rate (LIBOR) interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. 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
	(in millions)			
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Equity-commingled funds	$ 48	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	209	None	Daily	Not applicable
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Trust-owned life insurance	$ 86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	109	None	Daily	Not applicable

The nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company's investment in the money market funds.

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	**$6,132**	**$6,874**
2010	$6,187	$6,463

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 Alabama 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 electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. 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 three 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 clause.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *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 for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
39	2017	-

*mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2012 are immaterial.

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 earnings.

At December 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$100	3M LIBOR	2.22%*	January 2022	$ (1.6)
	300	3M LIBOR	2.90%*	December 2022	(16.6)
Total	$400				$(18.2)

*Weighted Average Rate

For the year ended December 31, 2011, the Company had realized net gains of $4 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

Subsequent to December 31, 2011, the Company settled $100 million of interest rate hedges related to the Series 2012A 4.10% Senior Notes issuance at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

The estimated pre-tax gains that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 is $0.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives and interest rate 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	**$-**	$1	Liabilities from risk management activities	**$36**	$31
	Other deferred charges and assets	**-**	1	Other deferred credits and liabilities	**12**	9
Total derivatives designated as hedging instruments for regulatory purposes		**$-**	$2		**$48**	$40
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$-**	$ -	Liabilities from risk management activities	**$18**	$ -
Total		**$-**	$2		**$66**	$40

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	**$36**	$(31)	Other current liabilities	**$-**	$1
	Other regulatory assets, deferred	**12**	(9)	Other regulatory liabilities, deferred	**-**	1
Total energy-related derivative gains (losses)		**$48**	$(40)		**$-**	$2

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in millions)				*(in millions)*	
Interest rate derivatives	**$(14)**	$-	$(5)	Interest expense, net of amounts capitalized	**$3**	$3	$(12)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

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 $10 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	**$1,320**	**$329**	**$152**
June 2011	**1,440**	**404**	**190**
September 2011	**1,671**	**523**	**264**
December 2011	**1,271**	**258**	**102**
March 2010	$1,495	$399	$203
June 2010	1,462	389	190
September 2010	1,706	497	259
December 2010	1,313	204	55

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

SELECTED FINANCIAL AND OPERATING DATA 2007-2011
Alabama Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions)	**$5,702**	$5,976	$5,529	$6,077	$5,360
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$708**	$707	$670	$616	$580
Cash Dividends on Common Stock (in millions)	**$774**	$586	$523	$491	$465
Return on Average Common Equity (percent)	**13.19**	13.31	13.27	13.30	13.73
Total Assets (in millions)	**$18,477**	$17,994	$17,524	$16,536	$15,747
Gross Property Additions (in millions)	**$1,016**	$956	$1,323	$1,533	$1,203
Capitalization (in millions):					
Common stock equity	**$5,342**	$5,393	$5,237	$4,854	$4,411
Preference stock	**343**	343	343	343	343
Redeemable preferred stock	**342**	342	342	342	340
Long-term debt	**5,632**	5,987	6,082	5,605	4,750
Total (excluding amounts due within one year)	**$11,659**	$12,065	$12,004	$11,144	$9,844
Capitalization Ratios (percent):					
Common stock equity	**45.8**	44.7	43.6	43.6	44.8
Preference stock	**2.9**	2.9	2.9	3.1	3.5
Redeemable preferred stock	**2.9**	2.8	2.8	3.0	3.4
Long-term debt	**48.4**	49.6	50.7	50.3	48.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,231,574**	1,235,128	1,229,134	1,220,046	1,207,883
Commercial	**196,270**	197,336	198,642	211,119	216,830
Industrial	**5,844**	5,770	5,912	5,906	5,849
Other	**746**	782	780	775	772
Total	**1,434,434**	1,439,016	1,434,468	1,437,846	1,431,334
Employees (year-end)	**6,632**	6,552	6,842	6,997	6,980

	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$2,144**	$2,283	$1,962	$1,998	$1,834
Commercial	**1,495**	1,535	1,430	1,459	1,314
Industrial	**1,306**	1,231	1,080	1,381	1,238
Other	**27**	27	25	24	21
Total retail	**4,972**	5,076	4,497	4,862	4,407
Wholesale - non-affiliates	**287**	465	620	712	627
Wholesale - affiliates	**244**	236	237	308	144
Total revenues from sales of electricity	**5,503**	5,777	5,354	5,882	5,178
Other revenues	**199**	199	175	195	182
Total	**$5,702**	$5,976	$5,529	$6,077	$5,360
Kilowatt-Hour Sales (in millions):					
Residential	**18,650**	20,417	18,071	18,380	18,874
Commercial	**14,173**	14,719	14,186	14,551	14,761
Industrial	**21,666**	20,622	18,555	22,075	22,806
Other	**214**	216	218	201	201
Total retail	**54,703**	55,974	51,030	55,207	56,642
Wholesale - non-affiliates	**4,330**	8,655	14,317	15,204	15,769
Wholesale - affiliates	**7,211**	6,074	6,473	5,256	3,241
Total	**66,244**	70,703	71,820	75,667	75,652
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.50**	11.18	10.86	10.87	9.71
Commercial	**10.55**	10.43	10.08	10.03	8.90
Industrial	**6.03**	5.97	5.82	6.26	5.43
Total retail	**9.09**	9.07	8.81	8.81	7.78
Wholesale	**4.60**	4.76	4.12	4.99	4.06
Total sales	**8.31**	8.17	7.45	7.77	6.84
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,138**	16,570	14,716	15,162	15,696
Residential Average Annual Revenue Per Customer	**$1,740**	$1,853	$1,597	$1,648	$1,525
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,553**	11,349	10,701	10,747	10,144
Summer	**11,500**	11,488	10,870	11,518	12,211
Annual Load Factor (percent)	**60.6**	62.6	59.8	60.9	59.4
Plant Availability (percent):					
Fossil-steam	**88.7**	92.9	88.5	90.1	88.2
Nuclear	**94.7**	88.4	93.3	94.1	87.5
Source of Energy Supply (percent):					
Coal	**52.5**	56.6	53.4	58.5	60.9
Nuclear	**20.8**	17.7	18.6	17.8	16.5
Hydro	**4.6**	5.0	7.9	2.9	1.8
Gas	**15.3**	14.0	11.8	9.2	8.7
Purchased power -					
From non-affiliates	**0.9**	1.6	2.0	2.9	1.8
From affiliates	**5.9**	5.1	6.3	8.7	10.3
Total	**100.0**	100.0	100.0	100.0	100.0

Directors

Whit Armstrong
Managing Member
Creeke Capital Investments, LLC

Ralph D. Cook
Attorney, Hare, Wynn, Newell & Newton

David J. Cooper, Sr.
Vice Chairman,
Cooper/T. Smith Corporation

Thomas A. Fanning
Chairman, President and CEO,
Southern Company

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

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

James K. Lowder
Chairman,
The Colonial Company

Charles D. McCrary
President and CEO,
Alabama Power Company

Malcolm Portera
Retired Chancellor, The University of Alabama System

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

C. Dowd Ritter
Retired Chairman and CEO,
Regions Financial Corporation

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

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

Officers

Charles D. McCrary
President and Chief Executive Officer

Philip C. Raymond
Executive Vice President, Chief Financial Officer and Treasurer

Steve R. Spencer
Executive Vice President

Zeke W. Smith
Executive Vice President

Gordon G. Martin
Senior Vice President and General Counsel

Theodore J. McCullough
Senior Vice President and Senior Production Officer

Greg Barker
Senior Vice President

Anita Allcorn-Walker
Vice President and Comptroller

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

Matthew W. Bowden
Vice President

Kenneth E. Coleman[1]
Vice President

Mark S. Crews
Vice President

Daniel K. Glover
Vice President

R. Myrk Harkins
Vice President

John O. Hudson, III
Vice President

Richard O. Hutto
Vice President

Stacy R. Kilcoyne
Vice President

Kathleen S. King
Vice President

Barbara J. Knight
Vice President

Richard J. Mandes, Jr.
Vice President

Kenneth F. Novak
Vice President

Leigh Davis-Perry
Vice President

Myrna J. Pittman[2]
Vice President

Quentin P. Riggins[3]
Vice President

Leslie L. Sanders
Vice President

R. Michael Saxon
Vice President

Don A. Scivley
Vice President

Julia H. Segars
Vice President

Nicholas C. Sellers
Vice President

Donna D. Smith
Vice President

Robert L. Weaver
Vice President

Ronald Q. Patterson
Assistant Comptroller

Melissa K. Caen
Assistant Secretary and Assistant Treasurer

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

Christopher R. Blake
Assistant Treasurer

1 **Resigned 7/11**
2 **Retired 7/11**
3 **Elected 9/11**

General

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

Profile

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.4 million customers within its service area of approximately 45,000 square miles. In 2011, retail energy sales accounted for 83 percent of the Company's total sales of 66 billion kilowatt-hours.

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

Trustee, Registrar, and Interest Paying Agent

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

Registrar, Transfer Agent, and Dividend Paying Agent

All series of Preferred and Preference Stock
Computershare Shareowner Services, LLC
480 Washington Boulevard
Jersey City, NJ 07310-1900
(800) 554-7626

www.bnymellon.com/shareowner/equityaccess

Number of Preferred Shareholders of record as of December 31, 2011 was 1,378.

Form 10-K

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

Alabama Power Company

600 North 18th Street
Birmingham, AL 35203
(205) 257-1000
www.alabamapower.com

Auditors

Deloitte & Touche LLP
420 North 20th Street
Suite 2400
Birmingham, AL 35203

Legal Counsel

Balch & Bingham LLP
P.O. Box 306
Birmingham, AL 35201

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