GULF POWER COMPANY

2011 Annual Report

GULF POWER
A SOUTHERN COMPANY

CONTENTS
Gulf Power Company 2011 Annual Report

SUMMARY

	2011	2010	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,519,812**	**$1,590,209**	(4.4)
Operating expenses	**1,295,088**	**1,343,409**	(3.6)
Net income after dividends on preference stock	**105,005**	**121,511**	(13.6)
Gross property additions	**337,830**	**285,379**	18.4
Total assets	**3,871,881**	**3,584,939**	8.0
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**11,040,286**	**11,359,195**	(2.8)
Sales for resale – non-affiliates	**2,012,986**	**1,675,079**	20.2
Sales for resale – affiliates	**2,607,873**	**2,436,883**	7.0
Total	**15,661,145**	**15,471,157**	1.2
Customers served at year-end	**432,536**	**430,658**	0.4
Peak-hour demand, net *(in megawatts)*	**2,527**	**2,544**	(0.7)
Capitalization Ratios *(percent)*:			
Common stock equity	**45.8**	**47.0**	
Preference stock	**4.0**	**4.3**	
Long-term debt (excluding amounts due within one year)	**50.2**	**48.7**	
Return on Average Common Equity *(percent)*	**9.55**	**11.69**	

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Gulf Power Company 2011 Annual Report

The management of Gulf 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.

Mark A. Crosswhite
President and Chief Executive Officer

Richard S. Teel
Vice President and Chief Financial Officer

February 24, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the "Company") (a wholly owned subsidiary of 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 67) referred to above present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 24, 2012

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a 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 prices, and storm restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On July 8, 2011, the Company filed a petition with the Florida Public Service Commission (PSC) requesting an increase in retail rates and charges to the extent necessary to generate additional gross annual revenues in the amount of $93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, to be operative beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 430,000 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 preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2011 Peak Season EFOR of 1.24% 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 preference stock is the primary measure of the Company's financial performance. The performance for net income after dividends on preference stock in 2011 was above target. The target net income was lower than the prior year's target due to increasing costs and reduced revenue growth due to the current economic environment, which were the primary drivers in the Company's decision to file a rate case in 2011. The Company's 2011 results compared with 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	4.80% or less	1.24%
Net income after dividends on preference stock	$101.6 million	$105.0 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis the Company places on reliability, customer satisfaction, and financial integrity, 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 preference stock was $105.0 million, a decrease of $16.5 million from the previous year. In 2010, net income after dividends on preference stock was $121.5 million, an increase of $10.3 million from the previous year. The decrease in net income after dividends on preference stock in 2011 was primarily due to an increase in other operations and maintenance expenses in 2011 and closer to normal weather in 2011 compared to 2010, partially offset by higher wholesale capacity revenues from non-affiliates. The increase in net income after dividends on preference stock in 2010 was primarily due to increased retail revenues due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010 when compared to the corresponding periods in 2009.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$ 1,519.8**	**$ (70.4)**	$ 288.0
Fuel	**662.3**	**(80.0)**	168.9
Purchased power	**90.5**	**(6.7)**	5.2
Other operations and maintenance	**311.3**	**30.7**	20.3
Depreciation and amortization	**129.7**	**8.2**	28.1
Taxes other than income taxes	**101.3**	**(0.5)**	7.3
Total operating expenses	**1,295.1**	**(48.3)**	229.8
Operating income	**224.7**	**(22.1)**	58.2
Total other income and (expense)	**(52.2)**	**(4.6)**	(29.4)
Income taxes	**61.3**	**(10.2)**	18.5
Net income	**111.2**	**(16.5)**	10.3
Dividends on preference stock	**6.2**	**-**	-
Net income after dividends on preference stock	**$ 105.0**	**$ (16.5)**	$ 10.3

Operating Revenues

Operating revenues for 2011 were $1,519.8 million, reflecting a decrease of $70.4 million from 2010. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2011	2010
	(in millions)	
Retail – prior year	**$ 1,308.7**	$ 1,106.6
Estimated change in –		
Rates and pricing	**2.0**	72.7
Sales growth (decline)	**3.9**	(2.3)
Weather	**(17.8)**	18.7
Fuel and other cost recovery	**(88.3)**	113.0
Retail – current year	**1,208.5**	1,308.7
Wholesale revenues –		
Non-affiliates	**133.6**	109.2
Affiliates	**111.3**	110.0
Total wholesale revenues	**244.9**	219.2
Other operating revenues	**66.4**	62.3
Total operating revenues	**$ 1,519.8**	$ 1,590.2
Percent change	**(4.4)%**	22.1%

Retail revenues decreased $100.2 million, or 7.7%, in 2011 compared to 2010 primarily as a result of lower fuel revenues and lower energy sales due to closer to normal weather in 2011 compared to 2010, partially offset by an increase related to interim retail rate revenues. Retail revenues increased $202.1 million, or 18.3%, in 2010 compared to 2009 primarily as a result of higher fuel and purchased power expenses in 2010 and revenues associated with higher projected environmental compliance costs in 2010. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Revenues associated with changes in rates and pricing include cost recovery provisions for energy conservation costs, environmental compliance costs, and interim retail revenues. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for additional information.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. For 2010, fuel and other cost recovery provisions also include the change in revenues related to 2009 recovery of storm damage restoration costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues" and "Property Damage Reserve" and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Total wholesale revenues were $244.9 million in 2011, an increase of $25.7 million, or 11.7%, compared to 2010 primarily due to a 41.6% increase in capacity revenues resulting from higher capacity rates. Total wholesale revenues were $219.2 million in 2010, an increase of $93.0 million, or 73.7%, compared to 2009 primarily to serve weather-related increases in affiliate demand as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010.

Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation.

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

	2011	2010	2009
		(in thousands)	
Unit power sales –			
Capacity	**$ 52,507**	$ 33,482	$ 24,466
Energy	**44,227**	31,379	33,122
Total	**96,734**	64,861	57,588
Other power sales –			
Capacity and other	**10,717**	11,158	11,060
Energy	**26,104**	33,153	25,457
Total	**36,821**	44,311	36,517
Total non-affiliated	**$ 133,555**	$ 109,172	$ 94,105

Revenues from unit power sales increased $31.9 million, or 49.1%, in 2011 primarily due to a 56.8% increase in capacity revenues related to higher capacity rates as a result of contracts effective June 2010. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in kilowatt-hour (KWH) sales. Revenues from other power sales decreased $7.5 million, or 16.9%, in 2011 primarily due to decreased energy revenues related to a 9.6% decrease in KWH sales. Revenues from unit power sales increased $7.3 million, or 12.6%, in 2010 primarily due to increased capacity revenues as a result of new contracts.

Revenues from other power sales increased $7.8 million, or 21.3%, in 2010 primarily due to increased KWH sales to serve weather-related increases in non-territorial demand.

Wholesale revenues from 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 the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause.

Other operating revenues increased $4.1 million, or 6.7%, in 2011 primarily due to a $3.4 million increase in revenues from other energy services. Other operating revenues decreased $7.2 million, or 10.4%, in 2010 primarily due to a $10.3 million decrease in revenues from other energy services, partially offset by higher franchise fees of $3.1 million. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses. Franchise fees have no impact on net income.

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 millions)				
Residential	**5,305**	**(6.1)%**	7.6%	**0.5%**	(0.2)%
Commercial	**3,911**	**(2.1)**	2.6	**0.0**	0.3
Industrial	**1,799**	**6.7**	(2.4)	**6.7**	(2.4)
Other	**25**	**(0.7)**	1.9	**(0.7)**	1.9
Total retail	**11,040**	**(2.8)**	(4.2)	**1.3%**	(0.3)%
Wholesale					
Non-affiliates	**2,013**	**20.2**	(7.6)		
Affiliates	**2,608**	**7.0**	180.0		
Total wholesale	**4,621**	**12.4**	53.2		
Total energy sales	**15,661**	**1.2%**	13.9%		

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

Residential KWH sales and commercial KWH sales decreased in 2011 compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Weather-adjusted 2011 KWH sales to residential and commercial customers remained relatively flat as compared to 2010. Residential KWH sales and commercial KWH sales increased in 2010 compared to 2009 primarily due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010 when compared to the corresponding periods in 2009. Weather-adjusted 2010 KWH sales to residential and commercial customers remained relatively flat as compared to 2009.

Industrial KWH sales increased 6.7% in 2011 compared to 2010 primarily resulting from the addition of a new large customer and higher customer load requirements and production levels. Industrial KWH sales decreased 2.4% in 2010 compared to 2009 primarily resulting from increased customer co-generation due to the lower cost of natural gas in 2010.

Wholesale KWH sales to non-affiliates increased 20.2% in 2011 compared to 2010 primarily resulting from higher KWHs scheduled by unit power customers. Wholesale KWH sales to non-affiliates decreased 7.6% in 2010 compared to 2009 primarily resulting from lower KWHs scheduled by unit power customers.

Wholesale KWH sales to affiliates increased 7.0% in 2011 compared to 2010 primarily resulting from the Company's lower priced natural gas resources available to serve affiliate demand. Wholesale KWH sales to affiliates increased 180% in 2010 compared to 2009 primarily to serve weather-related increases in affiliate demand due to colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010.

Fuel and Purchased Power Expenses

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

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

	2011	2010	2009
Total generation *(millions of KWHs)*	**12,035**	13,440	12,895
Total purchased power *(millions of KWHs)*	**4,349**	2,858	1,481
Sources of generation *(percent)* –			
Coal	**67%**	78%	69%
Gas	**33**	22	31
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.97**	5.10	4.27
Gas	**4.06**	4.68	4.66
Average cost of fuel, generated *(cents per net KWH)*	**4.67**	5.01	4.39
Average cost of purchased power *(cents per net KWH*)*	**4.39**	5.82	6.71

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

Total fuel and purchased power expenses were $752.8 million in 2011, a decrease of $86.7 million, or 10.3%, from the prior year costs. The net decrease in fuel and purchased power expenses was due to a $103.2 million decrease in the average cost of fuel and purchased power and a $70.3 million decrease related to KWHs generated, partially offset by an $86.8 million increase related to KWHs purchased. Total fuel and purchased power expenses were $839.5 million in 2010, an increase of $174.1 million, or 26.2%, from the prior year costs. The net increase in fuel and purchased power expenses was primarily due to a $116.3 million increase related to total KWHs generated and purchased and a $57.8 million increase in the cost of energy resulting primarily from an increase in the average cost of coal-fired generation and affiliated company power purchases.

Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. This decrease was primarily the result of a 13.3% decrease in the average cost of natural gas per KWH generated, a change in the source of generation to be more heavily weighted to lower cost, natural gas-fired generation, and a 10.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 52.2% increase in KWHs purchased. Fuel expense was $742.3 million in 2010, an increase of $168.9 million, or 29.5%, from the prior year costs. This increase was primarily the result of a 19.4% increase in the average cost of coal per KWH generated and a 4.2% increase in KWHs generated as a result of higher demand.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions between the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. Purchased power expense was $90.5 million in 2011, a decrease of $6.7 million, or 6.9%, from the prior year costs. This decrease was due to net decreases of $4.9 million in capacity costs and $1.8 million in energy costs. Purchased power expense was $97.2 million in 2010, an increase of $5.2 million, or 5.7%, from the prior year costs. This increase was due to a $15.0 million increase in capacity costs, offset by a $9.8 million decrease in energy costs.

The 2011 average cost of purchased power decreased 24.6% in 2011 compared to the prior period primarily as a result of a decrease in the average cost of natural gas. The 2010 average cost of purchased power decreased 13.3% compared to the prior period primarily as a result of an increase in the volume of KWHs purchased.

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.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses increased $30.7 million, or 11.0%, compared to the prior year primarily due to increases of $13.9 million in routine and planned outage maintenance expense at generation facilities, $3.2 million in other energy services, $10.4 million in labor expense, and $2.1 million in marketing programs. In 2010, other operations and maintenance expenses increased $20.3 million, or 7.8%, compared to the prior year primarily due to a $20.2 million increase in routine and planned outage maintenance expense at generation facilities.

Depreciation and Amortization

Depreciation and amortization increased $8.2 million, or 6.7%, in 2011 compared to the prior year primarily due to the addition of environmental control projects and other net additions to transmission and distribution facilities. Depreciation and amortization increased $28.1 million, or 30.1%, in 2010 compared to the prior year primarily due to the addition of an environmental control project at Plant Crist being placed into service in December 2009 and other net additions to generation and distribution facilities. Approximately $19.0 million of the 2010 increase was related to the environmental control project at Plant Crist and was recovered through the environmental clause; therefore, it had no material impact on net income.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $0.5 million, or 0.5%, in 2011 compared to the prior year primarily due to a $1.1 million decrease in gross receipts taxes, partially offset by a $0.7 million increase in property taxes. Taxes other than income taxes increased $7.3 million, or 7.7%, in 2010 compared to the prior year primarily due to a $5.5 million increase in gross receipts taxes and franchise fees and a $1.0 million increase in payroll taxes. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity increased $2.7 million, or 37.4%, in 2011 compared to the prior year primarily due to construction of environmental control projects at generating facilities. AFUDC equity decreased $16.6 million, or 69.7%, in 2010 compared to the prior year primarily due to an environmental control project at Plant Crist being placed into service in December 2009. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $6.3 million, or 12.0%, in 2011 compared to the prior year primarily due to increases in long-term debt levels resulting from the issuance of additional senior notes in 2011. These increases were partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects. Interest expense, net of amounts capitalized increased $13.5 million, or 35.3%, in 2010 compared to the prior year as the result of a reduction in capitalized interest for an environmental control project at Plant Crist being placed into service in December 2009. The increased interest was also primarily due to an increase in long-term debt levels resulting from the issuance of additional senior notes in 2010 to fund general corporate purposes, including the Company's continuous construction program.

Income Taxes

Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. Income taxes increased $18.5 million, or 34.9%, in 2010 compared to the prior year primarily as a result of higher earnings before income taxes and a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

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

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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 Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

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

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $1.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $141 million, $136 million, and $343 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 $523 million from 2012 through 2014 as follows:

	2012	**2013**	**2014**
		(in millions)	
Existing environmental statutes and regulations	$200	$137	$186

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $400 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could be approximately $1.8 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is approximately $400 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $375 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $105 million over the same 2012 through 2014 three-year period. These estimates are based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. The estimated costs are as follows:

	2012	**2013**	**2014**
		(in millions)	
MATS rule	Up to $45	Up to $90	Up to $240
Proposed water and coal combustion byproducts rules	Up to $5	Up to $25	Up to $75
Total potential incremental environmental compliance investments	**Up to $50**	**Up to $115**	**Up to $315**

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 2,663 MWs, of which 2,060 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 two of its largest coal units making up 705 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. Also see "PSC Matters – Environmental Cost Recovery" for information regarding potential construction of a scrubber on Plant Daniel Units 1 and 2, which are co-owned by the Company.

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

Compliance with 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 $1.1 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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

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

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

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

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

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. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

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. In addition, certain units in the State of Georgia, including Plant Scherer Unit 3, which is co-owned by the Company, are required to install specific emissions controls according to a schedule set forth in the state's Multi-Pollutant Rule, which is designed to reduce emissions of SO_2, NO_x, and mercury.

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.

In addition, the State of Florida is finalizing numeric nutrient water quality standards to limit the amount of nitrogen and phosphorous allowed in state waters. The impact of these standards will depend on the specific requirements of the final rule and cannot be determined at this time. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Coal Combustion Byproducts

The Company currently operates three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner 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 sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida, Georgia, and Mississippi each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

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

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described 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. See Note 3 to the Financial Statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

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

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

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

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

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

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 13 million metric tons of carbon dioxide equivalent.

The preliminary estimate of the Company's 2011 greenhouse gas emissions is approximately 10 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.

PSC Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On July 8, 2011, the Company filed a petition with the Florida PSC requesting an increase in retail rates to the extent necessary to generate additional gross annual revenues in the amount of $93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, effective beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 1, 2011, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2012. The net effect of the approved changes is a 1.1% rate decrease for residential customers using 1,000 KWHs per month. On February 14, 2012, the Florida PSC approved an additional reduction to the fuel cost recovery factors for the remainder of 2012, starting in March 2012. The effect of the approved change is a 2.7% decrease for residential customers using 1,000 KWHs per month. The billing factors for 2012 are intended to allow the Company to recover projected 2012 costs as well as refund or collect the 2011 over or under recovered amounts in 2012. Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters" respectively, for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved the Company's additional request to further reduce an estimated December 2012 over recovery balance of approximately $32 million.

The change in the fuel cost under recovered balance to an over recovered balance during 2011 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2011, the over recovered fuel balance was approximately $9.9 million, which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2010, the under recovered fuel balance was approximately $17.4 million, which is included in under recovered regulatory clause revenues, current in the balance sheets. See Note 1 to the financial statements under "Fuel Costs" and "Fuel Inventory" for additional information.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2011 and 2010, the Company had an over recovered purchased power capacity balance of approximately $8.0 million and $4.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the Florida Department of Environmental Protection for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that were implemented in the 2007 through 2011 timeframe. In April 2010, the Company filed an update to the plan, which was approved by the Florida PSC in November 2010. The Florida PSC acknowledged that the costs associated with the Company's CAIR and CAVR compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2011 and 2010, the over recovered environmental balance was approximately $10.0 million and $10.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 7 to the financial statements under "Construction Program" for additional information.

In July 2010, Mississippi Power Company (Mississippi Power) filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, and it is scheduled for completion in late 2015. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the Energy Conservation Cost Recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

See BUSINESS under "Rate Matters – Integrated Resource Planning – Gulf Power" in Item 1 for a discussion of the Company's 10-year site plan filed on an annual basis with the Florida PSC.

At December 31, 2011, the under recovered energy conservation balance was approximately $3.1 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2010, the over recovered energy conservation balance was approximately $2.9 million, which is included in other regulatory liabilities, current in the balance sheets.

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 $100 million and $120 million in 2012.

Other Matters

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

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 Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost based regulation by the FERC with respect to wholesale transmission rates. 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 and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

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

Pension and Other Postretirement Benefits

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

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

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.1 million or less change in total benefit expense and a $13 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to 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 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.

Net cash provided from operating activities totaled $376.2 million, $267.8 million, and $194.2 million for 2011, 2010, and 2009, respectively. The $108.4 million increase in net cash provided from operating activities in 2011 was primarily due to a $42.4 million increase related to the recovery of fuel costs and a $51.6 million increase from prepaid income taxes, primarily due to bonus depreciation. The $73.5 million increase in net cash provided from operating activities in 2010 was primarily due to a $99.2 million increase from deferred income taxes related to bonus depreciation and a $90.9 million decrease in fuel inventory, partially offset by a $109.4 million increase in accounts receivable related to fuel cost and a $25.7 million decrease related to the qualified pension plan.

Net cash used for investing activities totaled $343.5 million, $308.4 million, and $468.4 million for 2011, 2010, and 2009, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $337.8 million, $285.4 million, and $450.4 million for 2011, 2010, and 2009, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $31.8 million for 2011. Net cash provided from financing activities totaled $48.4 million and $279.4 million for 2010 and 2009, respectively. The $80.2 million decrease in cash from financing activities in 2011 was primarily due to a $175.0 million reduction in senior notes issuances in 2011, partially offset by a $104.9 million reduction in redemption of senior notes and other long-term debt in 2011. The $231.0 million decrease in net cash provided from financing activities in 2010 was due primarily to $194.4 million higher issuances of pollution control revenue bonds and common stock in 2009 and a net $54.3 million decrease in senior notes outstanding.

Significant balance sheet changes in 2011 include an increase of $234.3 million in property, plant, and equipment, primarily due to the addition of environmental control projects; an increase in other regulatory assets, deferred and other deferred credits and liabilities of $103.2 million and $54.1 million, respectively, primarily due to increases in power purchase agreements (PPAs) deferred capacity expense; an increase of $76.1 million in accumulated deferred income taxes, primarily due to bonus depreciation; and the issuance of common stock to Southern Company for $50 million.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.7% in 2011 and 43.1% 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, which were primarily from operating cash flows, security issuances, term loans, short-term indebtedness, 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 annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

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

At December 31, 2011, the Company had approximately $17.3 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires				Executable Term-Loans	
				One	Two
2012	2014	Total	Unused	Year	Years
$75	$165	$240	$240	$75	$-

(a) No credit arrangements expire in 2013, 2015, or 2016.

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.

During the second quarter 2011, the Company reviewed its lines of credit and made changes resulting in a temporary net increase of $40 million. In the third quarter 2011, the Company repaid a $30 million draw and decreased the amount of bank credit arrangements to $240 million. The Company also replaced $165 million of credit arrangements having one-year expirations with $165 million of credit arrangements having terms of three years. The Company expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2011, the Company had $69 million outstanding of pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings, excluding $3.6 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$111	0.22%	$53	0.24%	$111
Short-term bank debt	-	-	4	1.31%	30
Total	$111	0.22%	$57	0.32%	
December 31, 2010:					
Commercial paper	$ 92	0.29%	$44	0.25%	$108

(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 January 2011, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In May 2011, the Company issued $125 million aggregate principal amount of Series 2011A 5.75% Senior Notes due June 1, 2051. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a $110 million bank note, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 125
Below BBB- and/or Baa3	540

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 may enter 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 may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt at December 31, 2011 was 0.12%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $693,000 at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to natural gas purchases, the Company continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC.

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

	2011 Changes	2010 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (11,228)**	$ (13,687)
Contracts realized or settled	**11,004**	17,613
Current period changes[(a)]	**(40,561)**	(15,154)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (40,785)**	$ (11,228)

(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 $29.6 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 37.5 million mmBtu with a weighted average swap contract cost approximately $1.14 per mmBtu above market prices and a net hedge volume of 19.6 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $0.67 per mmBtu above market prices. Natural gas settlements 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. 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 9 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	Years 4&5
	(in thousands)			
Level 1	$ -	$ -	$ -	$ -
Level 2	(40,785)	(22,632)	(16,798)	(1,355)
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ (40,785)	$(22,632)	$(16,798)	$(1,355)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related 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 10 to the financial statements.

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

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could be approximately $1.8 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is approximately $400 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	**2013**	**2014**
Construction program:		*(in millions)*	
Base capital	$202	$151	$179
Existing environmental statutes and regulations	200	137	186
Total construction program base level capital investment	**$402**	**$288**	**$365**
Potential incremental environmental compliance investments:			
MATS rule	Up to $45	Up to $90	Up to $240
Proposed water and coal combustion byproducts rules	Up to $5	Up to $25	Up to $75
Total potential incremental environmental compliance investments	**Up to $50**	**Up to $115**	**Up to $315**

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; storm impacts; 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; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, 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 10 to the financial statements for additional information.

Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing[d]	Total
			(in thousands)			
Long-term debt[a] –						
Principal	$ -	$ 135,000	$ 110,000	$ 1,000,318	$ -	$ 1,245,318
Interest	58,036	113,462	103,502	760,552	-	1,035,552
Energy-related derivative obligations[b]	22,786	16,841	1,356	-	-	40,983
Preference stock dividends[c]	6,203	12,405	12,405	-	-	31,013
Operating leases	21,542	37,852	2,087	523	-	62,004
Unrecognized tax benefits and interest[d]	-	-	-	-	3,175	3,175
Purchase commitments[e] –						
Capital[f]	402,090	653,064	-	-	-	1,055,154
Limestone[g]	6,747	14,006	14,715	23,481	-	58,949
Coal	177,262	-	-	-	-	177,262
Natural gas[h]	128,969	286,050	207,864	176,530	-	799,413
Purchased power[i]	44,709	117,417	185,362	592,761	-	940,249
Long-term service agreements[j]	6,632	13,764	14,461	9,179	-	44,036
Pension and other postretirement benefit plans[k]	3,789	8,300	-	-	-	12,089
Total	$ 878,765	$ 1,408,161	$ 651,752	$ 2,563,344	$3,175	$ 5,505,197

(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.

(b) For additional information, see Notes 1 and 10 to the financial statements.

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

(d) The timing related to the realization of $3.2 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 $311 million, $280 million, and $260 million, 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 capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $50 million, up to $115 million, and up to $315 million for 2012, 2013, and 2014, respectively. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

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

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) The capacity and transmission related costs associated with power purchase agreements (PPA) are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

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

(k) 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, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, economic recovery, projections for the qualified pension plan and postretirement benefit plan, financing activities, start and completion of construction projects, 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 the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- 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

Gulf Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Revenues:			
Retail revenues	**$1,208,490**	$1,308,726	$1,106,568
Wholesale revenues, non-affiliates	**133,555**	109,172	94,105
Wholesale revenues, affiliates	**111,346**	110,051	32,095
Other revenues	**66,421**	62,260	69,461
Total operating revenues	**1,519,812**	1,590,209	1,302,229
Operating Expenses:			
Fuel	**662,283**	742,322	573,407
Purchased power, non-affiliates	**48,882**	41,278	23,706
Purchased power, affiliates	**41,612**	55,948	68,276
Other operations and maintenance	**311,358**	280,585	260,274
Depreciation and amortization	**129,651**	121,498	93,398
Taxes other than income taxes	**101,302**	101,778	94,506
Total operating expenses	**1,295,088**	1,343,409	1,113,567
Operating Income	**224,724**	246,800	188,662
Other Income and (Expense):			
Allowance for equity funds used during construction	**9,914**	7,213	23,809
Interest expense, net of amounts capitalized	**(58,150)**	(51,897)	(38,358)
Other income (expense), net	**(4,012)**	(2,888)	(3,652)
Total other income and (expense)	**(52,248)**	(47,572)	(18,201)
Earnings Before Income Taxes	**172,476**	199,228	170,461
Income taxes	**61,268**	71,514	53,025
Net Income	**111,208**	127,714	117,436
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$105,005**	$121,511	$111,233

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

STATEMENTS OF COMPREHENSIVE INCOME

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

Gulf Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Net Income After Dividends on Preference Stock	**$105,005**	$121,511	$111,233
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(542), and $1,132, respectively	**-**	(863)	1,803
Reclassification adjustment for amounts included in net income, net of tax of $360, $376, and $419, respectively	**573**	598	667
Total other comprehensive income (loss)	**573**	(265)	2,470
Comprehensive Income	**$105,578**	$121,246	$113,703

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

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	2011	2010	2009
		(in thousands)	
Operating Activities:			
Net income	**$111,208**	$ 127,714	$ 117,436
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**135,790**	127,897	99,564
Deferred income taxes	**63,228**	82,681	(16,545)
Allowance for equity funds used during construction	**(9,914)**	(7,213)	(23,809)
Pension, postretirement, and other employee benefits	**(356)**	(23,964)	1,769
Stock based compensation expense	**1,318**	1,101	933
Hedge settlements	**-**	1,530	-
Other, net	**(8,258)**	(4,126)	(5,173)
Changes in certain current assets and liabilities --			
-Receivables	**21,518**	(36,687)	83,245
-Prepayments	**10,150**	(10,796)	(192)
-Fossil fuel stock	**17,519**	15,766	(75,145)
-Materials and supplies	**(5,073)**	(6,251)	(1,642)
-Prepaid income taxes	**26,901**	(29,630)	(6,355)
-Property damage cost recovery	**-**	-	10,746
-Other current assets	**40**	55	(12)
-Accounts payable	**(2,528)**	15,683	7,890
-Accrued taxes	**1,475**	1,427	(2,404)
-Accrued compensation	**25**	5,122	(6,330)
-Over recovered regulatory clause revenues	**10,247**	3,192	11,215
-Other current liabilities	**2,937**	4,279	(960)
Net cash provided from operating activities	**376,227**	267,780	194,231
Investing Activities:			
Property additions	**(324,372)**	(285,793)	(421,309)
Investment in restricted cash from pollution control revenue bonds	**-**	-	(49,188)
Distribution of restricted cash from pollution control revenue bonds	**-**	6,347	42,841
Cost of removal net of salvage	**(14,471)**	(1,145)	(9,751)
Construction payables	**2,902**	(21,581)	(23,603)
Payments pursuant to long-term service agreements	**(8,007)**	(6,011)	(7,421)
Other investing activities	**420**	(262)	(5)
Net cash used for investing activities	**(343,528)**	(308,445)	(468,436)
Financing Activities:			
Increase (decrease) in notes payable, net	**21,324**	4,451	(49,599)
Proceeds --			
Common stock issued to parent	**50,000**	50,000	135,000
Capital contributions from parent company	**2,101**	2,242	22,032
Pollution control revenue bonds	**-**	21,000	130,400
Senior notes	**125,000**	300,000	140,000
Redemptions --			
Senior notes	**(608)**	(215,515)	(1,214)
Other long-term debt	**(110,000)**	-	-
Payment of preference stock dividends	**(6,203)**	(6,203)	(6,203)
Payment of common stock dividends	**(110,000)**	(104,300)	(89,300)
Other financing activities	**(3,419)**	(3,253)	(1,677)
Net cash provided from (used for) financing activities	**(31,805)**	48,422	279,439
Net Change in Cash and Cash Equivalents	**894**	7,757	5,234
Cash and Cash Equivalents at Beginning of Year	**16,434**	8,677	3,443
Cash and Cash Equivalents at End of Year	**$ 17,328**	$ 16,434	$ 8,677
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $3,951, $2,875 and $9,489 capitalized, respectively)	**$55,486**	$42,521	$40,336
Income taxes (net of refunds)	**(26,345)**	17,224	73,889
Noncash decrease in notes payable related to energy services	**-**	-	(8,309)
Noncash transactions - accrued property additions at year-end	**19,439**	14,475	42,050

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

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

Assets	**2011**	2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 17,328**	$ 16,434
Receivables --		
Customer accounts receivable	**72,754**	74,377
Unbilled revenues	**49,921**	64,697
Under recovered regulatory clause revenues	**5,530**	19,690
Other accounts and notes receivable	**13,350**	9,867
Affiliated companies	**14,844**	7,859
Accumulated provision for uncollectible accounts	**(1,962)**	(2,014)
Fossil fuel stock, at average cost	**147,567**	167,155
Materials and supplies, at average cost	**49,781**	44,729
Other regulatory assets, current	**35,849**	20,278
Prepaid expenses	**28,327**	58,412
Other current assets	**2,051**	3,585
Total current assets	**435,340**	485,069
Property, Plant, and Equipment:		
In service	**3,846,446**	3,634,255
Less accumulated provision for depreciation	**1,124,291**	1,069,006
Plant in service, net of depreciation	**2,722,155**	2,565,249
Construction work in progress	**287,173**	209,808
Total property, plant, and equipment	**3,009,328**	2,775,057
Other Property and Investments	**16,394**	16,352
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**48,210**	46,357
Prepaid pension costs	**-**	7,291
Other regulatory assets, deferred	**323,116**	219,877
Other deferred charges and assets	**39,493**	34,936
Total deferred charges and other assets	**410,819**	308,461
Total Assets	**$3,871,881**	$3,584,939

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

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

Liabilities and Stockholder's Equity	**2011**	2010
		(in thousands)
Current Liabilities:		
Securities due within one year	**$ -**	$ 110,000
Notes payable	**114,507**	93,183
Accounts payable --		
Affiliated	**54,874**	46,342
Other	**63,265**	68,840
Customer deposits	**35,779**	35,600
Accrued taxes --		
Accrued income taxes	**1,362**	3,835
Other accrued taxes	**12,114**	7,944
Accrued interest	**14,018**	13,393
Accrued compensation	**14,485**	14,459
Other regulatory liabilities, current	**35,639**	27,060
Liabilities from risk management activities	**22,786**	9,415
Other current liabilities	**22,916**	19,766
Total current liabilities	**391,745**	449,837
Long-Term Debt (See accompanying statements)	**1,235,447**	1,114,398
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**458,978**	382,876
Accumulated deferred investment tax credits	**6,760**	8,109
Employee benefit obligations	**109,740**	76,654
Other cost of removal obligations	**214,598**	204,408
Other regulatory liabilities, deferred	**44,843**	42,915
Other deferred credits and liabilities	**186,824**	132,708
Total deferred credits and other liabilities	**1,021,743**	847,670
Total Liabilities	**2,648,935**	2,411,905
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,124,948**	1,075,036
Total Liabilities and Stockholder's Equity	**$3,871,881**	$3,584,939
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

Gulf Power Company 2011 Annual Report

	2011	2010	**2011**	2010
	(in thousands)		*(percent of total)*	
Long Term Debt:				
Long-term notes payable --				
4.35% due 2013	**$ 60,000**	$ 60,000		
4.90% due 2014	**75,000**	75,000		
5.30% due 2016	**110,000**	110,000		
4.75% to 5.90% due 2017-2051	**691,363**	566,971		
Variable rates (0.71% at 1/1/11) due 2011	**-**	110,000		
Total long-term notes payable	**936,363**	921,971		
Other long-term debt --				
Pollution control revenue bonds --				
1.75% to 6.00% due 2022-2049	**239,625**	239,625		
Variable rates (0.12% to 0.16% at 1/1/12) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	308,955		
Unamortized debt discount	**(9,871)**	(6,528)		
Total long-term debt (annual interest requirement -- $58.0 million)	**1,235,447**	1,224,398		
Less amount due within one year	**-**	110,000		
Long-term debt excluding amount due within one year	**1,235,447**	1,114,398	**50.2%**	48.7%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares--preferred stock				
- 10,000,000 shares--preference stock				
Outstanding - $100 par or stated value -- 6% preference stock	**53,886**	53,886		
-- 6.45% preference stock	**44,112**	44,112		
- 1,000,000 shares (non-cumulative)				
Total preference stock (annual dividend requirement -- $6.2 million)	**97,998**	97,998	**4.0**	4.3
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 20,000,000 shares				
Outstanding - 2011: 4,142,717 shares				
Outstanding - 2010: 3,642,717 shares	**353,060**	303,060		
Paid-in capital	**542,709**	538,375		
Retained earnings	**231,333**	236,328		
Accumulated other comprehensive income (loss)	**(2,154)**	(2,727)		
Total common stockholder's equity	**1,124,948**	1,075,036	**45.8**	47.0
Total Capitalization	**$2,458,393**	$2,287,432	**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

Gulf Power Company 2011 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2008	1,793	$118,060	$511,547	$197,417	$(4,932)	$822,092
Net income after dividends on preference stock	-	-	-	111,233	-	111,233
Issuance of common stock	1,350	135,000	-	-	-	135,000
Capital contributions from parent company	-	-	23,030	-	-	23,030
Other comprehensive income (loss)	-	-	-	-	2,470	2,470
Cash dividends on common stock	-	-	-	(89,300)	-	(89,300)
Change in benefit plan measurement date	-	-	-	(233)	-	(233)
Balance at December 31, 2009	3,143	253,060	534,577	219,117	(2,462)	1,004,292
Net income after dividends on preference stock	-	-	-	121,511	-	121,511
Issuance of common stock	500	50,000	-	-	-	50,000
Capital contributions from parent company	-	-	3,798	-	-	3,798
Other comprehensive income (loss)	-	-	-	-	(265)	(265)
Cash dividends on common stock	-	-	-	(104,300)	-	(104,300)
Balance at December 31, 2010	**3,643**	**303,060**	**538,375**	**236,328**	**(2,727)**	**1,075,036**
Net income after dividends on preference stock	**-**	**-**	**-**	**105,005**	**-**	**105,005**
Issuance of common stock	**500**	**50,000**	**-**	**-**	**-**	**50,000**
Capital contributions from parent company	**-**	**-**	**4,334**	**-**	**-**	**4,334**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**573**	**573**
Cash dividends on common stock	**-**	**-**	**-**	**(110,000)**	**-**	**(110,000)**
Balance at December 31, 2011	**4,143**	**$353,060**	**$542,709**	**$231,333**	**$(2,154)**	**$1,124,948**

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida 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 $97 million, $99 million, and $87 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 agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $6.7 million, $8.9 million, and $3.9 million and Mississippi Power $23.4 million, $25.0 million, and $20.9 million in 2011, 2010, and 2009, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a power purchase agreement (PPA) with Southern Power for a total of approximately 292 megawatts (MWs) annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $14.3 million, $14.5 million, and $12.4 million in 2011, 2010, and 2009, respectively, and fuel costs associated with the PPA were $1.8 million, $3.3 million, and $0.4 million in 2011, 2010, and 2009, respectively. These costs have been approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. Additionally, the Company had $4.2 million of deferred capacity expenses included in prepaid expenses and other regulatory liabilities, current in the balance sheets at December 31, 2011 and 2010, respectively. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

The Company has an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $2.4 million, $2.4 million, and $1.4 million in 2011, 2010, and 2009, respectively, for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $138.5 million for the entire project. These costs are estimated to begin in 2012 and will continue through 2023. These costs have been approved for recovery by the Florida PSC through the Company's purchase power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

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 2010 or 2009. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million. The Company did not receive any significant services in 2011.

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 and Purchased Power Commitments" for additional information.

In 2010, the Company purchased an assembly fluted compressor from Georgia Power and an unbucketed turbine rotor from Southern Power for $3.9 million and $6.3 million, respectively. The Company also sold a universal distance piece to Southern Power, a compressor rotor and blades to Georgia Power, and a turbine rotor and blades to Mississippi Power for $0.6 million, $3.9 million, and $6.2 million, respectively. There were no significant affiliate transactions for 2011 or 2009.

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 thousands)		
Deferred income tax charges	**$ 44,533**	$ 42,352	(a)
Deferred income tax charges – Medicare subsidy	**4,005**	4,332	(b)
Asset retirement obligations	**(5,653)**	(4,310)	(a,j)
Other cost of removal obligations	**(214,598)**	(204,408)	(a)
Deferred income tax credits	**(8,113)**	(9,362)	(a)
Loss on reacquired debt	**14,437**	15,874	(c)
Vacation pay	**8,973**	8,288	(d,j)
Under recovered regulatory clause revenues	**3,133**	17,437	(e)
Over recovered regulatory clause revenues	**(27,950)**	(17,703)	(e)
Property damage reserve	**(30,473)**	(27,593)	(f)
Fuel-hedging (realized and unrealized) losses	**43,071**	15,024	(g,j)
Fuel-hedging (realized and unrealized) gains	**(197)**	(2,376)	(g,j)
PPA charges	**94,986**	52,404	(j,k)
Generation site selection/evaluation costs	**20,415**	12,814	(l)
Other assets	**1,675**	833	(e,j)
Environmental remediation	**61,625**	61,749	(h,j)
PPA credits	**(7,536)**	(7,536)	(j,k)
Other liabilities	**(798)**	(930)	(f)
Retiree benefit plans, net	**116,091**	74,930	(i,j)
Total assets (liabilities), net	**$ 117,626**	$ 31,819	

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 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.
(b) Recovered and amortized over periods not exceeding 14 years. See Note 5 under "Current and Deferred Income Taxes" for additional information.
(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.
(d) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.
(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.
(f) Recorded and recovered or amortized as approved by the Florida PSC.
(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the fuel cost recovery clause.
(h) Recovered through the environmental cost recovery clause when the remediation is performed.
(i) Recovered and amortized over the average remaining service period which may range up to 15 years. Includes $239 thousand related to other postretirement benefits. 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) Recovered over the life of the PPA for periods up to 14 years.
(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

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 to be reflected in rates.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

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 thousands)	
Generation	**$ 2,283,494**	$ 2,157,619
Transmission	**368,542**	337,055
Distribution	**1,030,546**	982,022
General	**161,322**	154,762
Plant acquisition adjustment	**2,542**	2,797
Total plant in service	**$ 3,846,446**	$ 3,634,255

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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2011, 3.5% in 2010, and 3.1% in 2009. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation 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.

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 an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with 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 Florida PSC, and are reflected in the balance sheets.

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

	2011	2010
	(in thousands)	
Balance at beginning of year	**$ 11,470**	$ 12,608
Liabilities incurred	**106**	-
Liabilities settled	**(1,050)**	(1,794)
Accretion	**545**	656
Cash flow revisions	**(342)**	-
Balance at end of year	**$ 10,729**	$ 11,470

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. The average annual AFUDC rate was 7.65% for each of the years 2011, 2010, and 2009. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 11.75%, 7.39%, and 26.64% for 2011, 2010, and 2009, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC-approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2011, 2010, and 2009. As of December 31, 2011 and 2010, the balance in the Company's property damage reserve totaled approximately $30.5 million and $27.6 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. Such a surcharge was authorized in 2005 after Hurricane Ivan in 2004 and was extended by a 2006 Florida PSC order approving a stipulation to address costs incurred as a result of Hurricanes Dennis and Katrina in 2005. Under the 2006 Florida PSC order, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company would be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism. After the effective date of new base rates, the Company will retain the right to request relief on an expedited basis from the Florida PSC without the thresholds set forth in the stipulation.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $2.7 million and $2.0 million at December 31, 2011 and 2010, respectively. For 2011, $1.6 million and $1.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2010, $1.6 million and $0.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There are no liabilities in excess of the reserve balance at December 31, 2011. Liabilities in excess of the reserve balance of $0.8 million at December 31, 2010 were included in deferred credits and other liabilities in the balance sheet. There were no corresponding regulatory assets at December 31, 2011. Corresponding regulatory assets of $0.8 million at December 31, 2010 are included in current assets in the balance sheet.

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 oil, natural gas, coal, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida 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 9 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 Florida 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 10 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 preference stock dividends, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, no other postretirement trust contributions are expected.

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%**	5.53%	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	**8.11**	8.18	8.36

*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 thousands)	
Benefit obligation	$ 3,446	$(2,943)
Service and interest costs	223	(191)

Pension Plans

The total accumulated benefit obligation for the pension plans was $321 million at December 31, 2011 and $290 million 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 thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 316,286**	$ 298,886
Service cost	**8,431**	7,853
Interest cost	**17,074**	17,305
Benefits paid	**(13,807)**	(13,401)
Plan amendments	**-**	460
Actuarial loss (gain)	**24,850**	5,183
Balance at end of year	**352,834**	316,286
Change in plan assets		
Fair value of plan assets at beginning of year	**307,828**	254,059
Actual return (loss) on plan assets	**9,552**	38,736
Employer contributions	**751**	28,434
Benefits paid	**(13,807)**	(13,401)
Fair value of plan assets at end of year	**304,324**	307,828
Accrued liability	**$ (48,510)**	$ (8,458)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $336 million and $17 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 thousands)	
Prepaid pension costs	**$ -**	$ 7,291
Other regulatory assets	**115,853**	75,096
Current liabilities, other	**(794)**	(778)
Employee benefit obligations	**(47,716)**	(14,971)

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 thousands)	
Prior service cost	**$ 6,402**	$ 7,664	**$ 1,262**
Net (gain) loss	**109,451**	67,432	**3,913**
Other regulatory assets	**$115,853**	$ 75,096	

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 thousands)
Balance at December 31, 2009	$ 85,194
Net (gain) loss	(8,857)
Change in prior service costs	459
Reclassification adjustments:	
Amortization of prior service costs	(1,302)
Amortization of net gain (loss)	(398)
Total reclassification adjustments	(1,700)
Total change	(10,098)
Balance at December 31, 2010	$ 75,096
Net (gain) loss	**42,531**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of prior service costs	**(1,262)**
Amortization of net gain (loss)	**(512)**
Total reclassification adjustments	**(1,774)**
Total change	**40,757**
Balance at December 31, 2011	**$115,853**

Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 8,431**	$ 7,853	$ 6,478
Interest cost	**17,074**	17,305	17,139
Expected return on plan assets	**(27,232)**	(24,695)	(24,357)
Recognized net (gain) loss	**512**	398	224
Net amortization	**1,262**	1,302	1,478
Net periodic pension cost	**$ 47**	$ 2,163	$ 962

Net periodic pension cost 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 thousands)
2012	$ 15,372
2013	15,950
2014	16,655
2015	17,315
2016	18,045
2017 to 2021	104,528

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 thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 69,617**	$ 72,640
Service cost	**1,132**	1,304
Interest cost	**3,658**	4,121
Benefits paid	**(4,189)**	(4,068)
Actuarial (gain) loss	**292**	(4,704)
Plan amendments	**-**	-
Retiree drug subsidy	**413**	324
Balance at end of year	**70,923**	69,617
Change in plan assets		
Fair value of plan assets at beginning of year	**15,697**	14,973
Actual return (loss) on plan assets	**514**	2,010
Employer contributions	**2,543**	2,458
Benefits paid	**(3,776)**	(3,744)
Fair value of plan assets at end of year	**14,978**	15,697
Accrued liability	**$ (55,945)**	$ (53,920)

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 thousands)	
Regulatory assets	**$ 239**	$ -
Regulatory liabilities	**-**	(166)
Current liabilities, other	**(624)**	(211)
Employee benefit obligations	**(55,321)**	(53,709)

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 thousands)	
Prior service cost	**$ 510**	$ 695	**$ 186**
Net (gain) loss	**(464)**	(1,311)	**-**
Transition obligation	**193**	450	**193**
Regulatory assets (liabilities)	**$ 239**	$ (166)	

The changes in the balance of regulatory assets and regulatory liabilities 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	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2009	$ 5,861	$ -
Net (gain) loss	(5,455)	(166)
Change in prior service costs/transition obligation	-	-
Reclassification adjustments:		
Amortization of transition obligation	(257)	-
Amortization of prior service costs	(186)	-
Amortization of net gain (loss)	37	-
Total reclassification adjustments	(406)	-
Total change	(5,861)	(166)
Balance at December 31, 2010	$ -	$ (166)
Net (gain) loss	**635**	**166**
Change in prior service costs/transition obligation	**-**	**-**
Reclassification adjustments:		
Amortization of transition obligation	**(257)**	**-**
Amortization of prior service costs	**(186)**	**-**
Amortization of net gain (loss)	**47**	**-**
Total reclassification adjustments	**(396)**	**-**
Total change	**239**	**166**
Balance at December 31, 2011	**$ 239**	**$ -**

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

	2011	2010	2009
		(in thousands)	
Service cost	**$ 1,132**	$ 1,304	$ 1,328
Interest cost	**3,658**	4,121	4,705
Expected return on plan assets	**(1,445)**	(1,481)	(1,436)
Net amortization	**396**	406	548
Net postretirement cost	**$ 3,741**	$ 4,350	$ 5,145

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 thousands)	
2012	$ 4,475	$ (481)	$ 3,994
2013	4,684	(537)	4,147
2014	4,927	(597)	4,330
2015	5,146	(661)	4,485
2016	5,354	(729)	4,625
2017 to 2021	27,719	(3,924)	23,795

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	25%	**28%**	28%
International equity	24	**24**	26
Domestic fixed income	26	**26**	25
Special situations	3	**-**	-
Real estate investments	13	**13**	12
Private equity	9	**9**	9
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.
- ***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.

	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 thousands)		
Assets:				
Domestic equity*	$ 51,686	$ 23,857	$ -	$ 75,543
International equity*	53,130	15,223	-	68,353
Fixed income:				
U.S. Treasury, government, and agency bonds	-	19,375	-	19,375
Mortgage- and asset-backed securities	-	6,047	-	6,047
Corporate bonds	-	37,274	120	37,394
Pooled funds	-	16,998	-	16,998
Cash equivalents and other	30	6,228	-	6,258
Real estate investments	9,838	-	34,989	44,827
Private equity	-	-	26,053	26,053
Total	$ 114,684	$ 125,002	$ 61,162	$ 300,848

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 57,023	$ 23,012	$ 31	$ 80,066
International equity*	57,515	19,940	-	77,455
Fixed income:				
U.S. Treasury, government, and agency bonds	-	13,703	-	13,703
Mortgage- and asset-backed securities	-	11,122	-	11,122
Corporate bonds	-	26,760	92	26,852
Pooled funds	-	9,063	-	9,063
Cash equivalents and other	92	21,537	-	21,629
Real estate investments	8,295	-	30,355	38,650
Private equity	-	-	28,727	28,727
Total	$ 122,925	$ 125,137	$ 59,205	$ 307,267
Liabilities:				
Derivatives	(31)	-	-	(31)
Total	$ 122,894	$ 125,137	$ 59,205	$ 307,236

*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 thousands)			
Beginning balance	**$ 30,355**	**$ 28,727**	$ 24,699	$ 25,053
Actual return on investments:				
Related to investments held at year end	**3,021**	**(538)**	2,596	2,954
Related to investments sold during the year	**896**	**1,941**	810	810
Total return on investments	**3,917**	**1,403**	3,406	3,764
Purchases, sales, and settlements	**717**	**(4,077)**	2,250	(90)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 34,989**	**$ 26,053**	$ 30,355	$ 28,727

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 thousands)		
Assets:				
Domestic equity*	$ 2,445	$ 1,128	$ -	$ 3,573
International equity*	2,511	719	-	3,230
Fixed income:				
U.S. Treasury, government, and agency bonds	-	918	-	918
Mortgage- and asset-backed securities	-	286	-	286
Corporate bonds	-	1,761	-	1,761
Pooled funds	-	1,328	-	1,328
Cash equivalents and other	1	295	-	296
Real estate investments	466	-	1,657	2,123
Private equity	-	-	1,232	1,232
Total	$ 5,423	$ 6,435	$ 2,889	$ 14,747

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 2,727	$ 1,100	$ 1	$ 3,828
International equity*	2,751	955	-	3,706
Fixed income:				
U.S. Treasury, government, and agency bonds	-	655	-	655
Mortgage- and asset-backed securities	-	533	-	533
Corporate bonds	-	1,280	-	1,280
Pooled funds	-	953	-	953
Cash equivalents and other	3	1,030	-	1,033
Real estate investments	396	-	1,452	1,848
Private equity	-	-	1,375	1,375
Total	$ 5,877	$ 6,506	$ 2,828	$ 15,211

*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 thousands)		
Beginning balance	**$ 1,452**	**$ 1,375**	$ 1,326	$ 1,346
Actual return on investments:				
Related to investments held at year end	**129**	**(26)**	30	-
Related to investments sold during the year	**42**	**77**	40	34
Total return on investments	**171**	**51**	70	34
Purchases, sales, and settlements	**34**	**(194)**	56	(5)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 1,657**	**$ 1,232**	$ 1,452	$ 1,375

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 $3.7 million, $3.6 million, and $3.7 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment 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 Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

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

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case.

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

Hurricane Katrina Case

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

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2011, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately \$61.6 million. For 2011, approximately \$2.4 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately \$59.2 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.

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

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On July 8, 2011, the Company filed a petition with the Florida PSC requesting an increase in retail rates to the extent necessary to generate additional gross annual revenues in the amount of \$93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, effective beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 1, 2011, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2012. The net effect of the approved changes is a 1.1% rate decrease for residential customers using 1,000 KWHs per month. On February 14, 2012, the Florida PSC approved an additional reduction to the fuel cost recovery factors for the remainder of 2012, starting in March 2012. The effect of the approved change is a 2.7% decrease for residential customers using 1,000 KWHs per month. The billing factors for 2012 are intended to allow the Company to recover projected 2012 costs as well as refund or collect the 2011 over or under recovered amounts in 2012. Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved the Company's additional request to further reduce an estimated December 2012 over recovery balance of approximately $32 million.

The change in the fuel cost under recovered balance to an over recovered balance during 2011 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2011, the over recovered fuel balance was approximately $9.9 million, which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2010, the under recovered fuel balance was approximately $17.4 million, which is included in under recovered regulatory clause revenues, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2011 and 2010, the Company had an over recovered purchased power capacity balance of approximately $8.0 million and $4.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that were implemented in the 2007 through 2011 timeframe. In April 2010, the Company filed an update to the plan, which was approved by the Florida PSC in November 2010. The Florida PSC acknowledged that the costs associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2011 and 2010, the over recovered environmental balance was approximately $10.0 million and $10.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

In July 2010, Mississippi Power filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, and it is scheduled for completion in late 2015. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filling have been made. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the Energy Conservation Cost Recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

At December 31, 2011, the under recovered energy conservation balance was approximately $3.1 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2010, the over recovered energy conservation balance was approximately $2.9 million, which is included in other regulatory liabilities, current in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

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

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

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

At December 31, 2011, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	**Plant Daniel Units 1 & 2 (coal)**
	(in thousands)	
Plant in service	$ 366,747[a]	$ 270,690
Accumulated depreciation	110,308	157,684
Construction work in progress	2,256	27,544
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.5 million.

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 Florida. 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 thousands)	
Federal –			
Current	**$ (1,548)**	$ (14,115)	$ 62,980
Deferred	**56,087**	77,452	(14,453)
	54,539	63,337	48,527
State –			
Current	**(412)**	2,948	6,590
Deferred	**7,141**	5,229	(2,092)
	6,729	8,177	4,498
Total	**$ 61,268**	$ 71,514	$ 53,025

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 thousands)	
Deferred tax liabilities–		
Accelerated depreciation	**$ 496,392**	$ 413,490
Fuel recovery clause	**-**	7,062
Pension and other employee benefits	**25,268**	23,990
Regulatory assets associated with employee benefit obligations	**44,871**	29,054
Regulatory assets associated with asset retirement obligations	**4,345**	4,646
Other	**14,804**	15,793
Total	**585,680**	494,035
Deferred tax assets–		
Federal effect of state deferred taxes	**16,684**	14,757
Postretirement benefits	**16,769**	20,723
Fuel recovery clause	**2,531**	-
Pension and other employee benefits	**49,116**	33,047
Property reserve	**13,159**	12,712
Other comprehensive loss	**1,353**	1,712
Asset retirement obligations	**4,345**	4,646
Alternative minimum tax carryforward	**7,151**	-
Other	**20,191**	19,727
Total	**131,299**	107,324
Net deferred tax liabilities	**454,381**	386,711
Portion included in current assets (liabilities), net	**4,597**	(3,835)
Accumulated deferred income taxes	**$ 458,978**	$ 382,876

At December 31, 2011, the tax-related regulatory assets to be recovered from customers were $48.5 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 AFUDC. In 2010, the Company deferred $4.5 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 amortization expense over the remaining average service life of 14 years. Amortization amounted to $0.3 million in 2011.

At December 31, 2011, the tax-related regulatory liabilities to be credited to customers were $8.1 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million in 2011, $1.5 million in 2010, and $1.6 million in 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

Effective Tax Rate

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

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.7	1.7
Non-deductible book depreciation	**0.5**	0.3	0.3
Difference in prior years' deferred and current tax rate	**(0.3)**	(0.3)	(0.4)
Production activities deduction	**-**	-	(0.9)
AFUDC equity	**(2.0)**	(1.3)	(4.9)
Other, net	**(0.2)**	(0.5)	0.3
Effective income tax rate	**35.5%**	35.9%	31.1%

The decrease in the 2011 effective tax rate is primarily the result of an increase in AFUDC equity, which is not taxable.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $1.0 million, resulting in a balance of $2.9 million as of December 31, 2011.

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

	2011	2010	2009
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$3,870**	$ 1,639	$ 294
Tax positions from current periods	**540**	1,027	455
Tax positions from prior periods	**(1,518)**	1,204	890
Reductions due to settlements	**-**	-	-
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$ 2,892**	$ 3,870	$ 1,639

The tax positions increase 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 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2011	2010	2009
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 1,804**	$ 1,826	$ 1,639
Tax positions not impacting the effective tax rate	**1,088**	2,044	-
Balance of unrecognized tax benefits	**$ 2,892**	$ 3,870	$ 1,639

The tax positions impacting the effective tax rate for 2011 relate primarily to the production activities deduction. 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 thousands)	
Interest accrued at beginning of year	**$ 210**	$ 90	$ 17
Interest reclassified due to settlements	**-**	-	-
Interest accrued during the year	**73**	120	73
Balance at end of year	**$ 283**	$ 210	$ 90

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 2010-2012, 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 $8 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

Securities Due Within One Year

At December 31, 2011, the Company had no securities due within one year.

Maturities through 2016 applicable to total long-term debt are as follows: $60 million in 2013; $75 million in 2014; and $110 million in 2016. There are no scheduled maturities in 2012 and 2015.

Senior Notes

At December 31, 2011 and 2010, the Company had a total of $936.4 million and $812.0 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company which totaled approximately $41 million at December 31, 2011.

In May 2011, the Company issued $125 million aggregate principal amount of Series 2011A 5.75% Senior Notes due June 1, 2051. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a $110 million bank note, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. At December 31, 2011 and 2010, the Company had a total of $309 million and $309 million of outstanding pollution control revenue bonds, respectively, and is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2011. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2011, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. On January 20, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

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 a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. 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 subsidiaries.

Bank Credit Arrangements

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

Expires[(a)]				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
$75	$165	$240	$240	$75	$-

(a) No credit arrangements expire in 2013, 2015, or 2016.

During 2011, the Company reviewed its lines of credit and replaced $165 million of credit arrangements having one-year expirations with $165 million of credit arrangements having terms of three years. The Company expects to renew its credit arrangements, as needed, prior to expiration. During the second quarter 2011, the Company reviewed its lines of credit and made changes resulting in a temporary net increase of $40 million. In the third quarter 2011, the Company repaid a $30 million draw and decreased the amount of bank credit arrangements to $240 million. Of the $240 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $171 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Annual commitment fees average less than ¼ of 1% for the Company.

Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65%, as defined in the arrangements. At December 31, 2011, the Company was in compliance with these covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

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

Details of short-term borrowings, excluding $3.6 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$111	0.22%	$53	0.24%	$111
Short-term bank debt	-	N/A	4	1.31%	30
Total	$111	0.22%	$57	0.32%	
December 31, 2010:					
Commercial paper	$ 92	0.29%	$44	0.25%	$108

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

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $402 million, $288 million, and $365 million for 2012, 2013, and 2014, respectively. These amounts include 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 $200 million, $137 million, and $186 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's 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; Florida 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. The Company does not have any significant new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for a combined cycle generating facility. The LTSA provides that GE will perform all planned inspections on the covered equipment, which generally 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 limits and scope specified in the LTSA.

In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under the LTSA for facilities owned are currently estimated at $44.0 million over the remaining life of the LTSA, which is currently estimated to be up to six years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made under the LTSA prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in deferred charges and other assets in the balance sheets for 2011 and 2010. 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 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. 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 0.7 million tons, equating to approximately $59 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $6.7 million in 2012, $6.9 million in 2013, $7.1 million in 2014, $7.3 million in 2015, and $7.4 million in 2016. Limestone costs are recovered through the environmental cost recovery clause.

Fuel and Purchased Power 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 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. Also, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments		
	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2012	$ 44,709	$ 128,969	$ 177,262
2013	49,485	153,186	-
2014	67,932	132,864	-
2015	92,808	106,581	-
2016	92,554	101,283	-
2017 and thereafter	592,761	176,530	-
Total	$ 940,249	$ 799,413	$ 177,262

*Included above is $173.6 million in obligations with affiliated companies. Certain PPAs are accounted for as operating leases.

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The 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.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Rental expenses related to these operating leases totaled $21.9 million, $23.1 million, and $10.1 million for 2011, 2010, and 2009, respectively.

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

	Minimum Lease Payments		
	Barges & Rail Cars	Other	Total
		(in thousands)	
2012	$ 21,022	$ 520	$ 21,542
2013	19,530	233	19,763
2014	17,958	131	18,089
2015	1,147	-	1,147
2016	940	-	940
2017 and thereafter	523	-	523
Total	$ 61,120	$ 884	$ 62,004

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum rail cars for the transportation of coal to Plant Daniel. The Company has the option to purchase the rail cars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other rail cars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $2.6 million in 2011, $3.5 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2016 will average approximately $2.1 million and after 2016, lease payments total in aggregate approximately $0.5 million.

The Company has other operating lease agreements for aluminum rail cars for transportation of coal to Plant Scholz and to the Alabama State Docks located in Mobile, Alabama. At the Alabama State Docks this coal is transferred from the railcar to barge for transportation to Plant Crist and Plant Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $4.3 million in 2011, $3.9 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2014 will average approximately $3.0 million.

The Company has operating lease agreements for barges and tow boats for the transport of coal to Plants Crist and Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $12.8 million in 2011, $13.5 million in 2010, and none in 2009. The Company's annual barge and tow boat lease payments for 2012 through 2014 will average approximately $13.6 million.

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 276 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	1,735,965	$ 32.47
Granted	242,530	38.08
Exercised	(479,832)	31.33
Cancelled	-	-
Outstanding at December 31, 2011	**1,498,663**	**$ 33.75**
Exercisable at December 31, 2011	**906,637**	**$ 33.55**

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 $18.8 million and $11.6 million, respectively.

As of December 31, 2011, there was $0.4 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $0.7 million, $0.8 million, and $0.9 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.4 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 $3.2 million, $1.6 million, and $0.2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.2 million, $0.6 million, and $0.1 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 35,568. During 2011, 31,457 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 363 performance share units were forfeited resulting in 66,662 unvested units outstanding at December 31, 2011.

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

9. 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 thousands)		
Assets:				
Energy-related derivatives	$ -	$ 198	$ -	$ 198
Cash equivalents	13,949	-	-	13,949
Total	$ 13,949	$ 198	$ -	$ 14,147
Liabilities:				
Energy-related derivatives	$ -	$40,983	$ -	$ 40,983

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 thousands)		
Assets:				
Energy-related derivatives	$ -	$ 2,380	$ -	$ 2,380
Cash equivalents	11,770	-	-	11,770
Total	$ 11,770	$ 2,380	$ -	$ 14,150
Liabilities:				
Energy-related derivatives	$ -	$13,608	$ -	$ 13,608

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 interest rates. See Note 10 for additional information on how these derivatives are used.

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

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2011:	*(in thousands)*			
Cash equivalents:				
Money market funds	$13,949	None	Daily	Not applicable
As of December 31, 2010:				
Cash equivalents:				
Money market funds	$11,770	None	Daily	Not applicable

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 thousands)	
Long-term debt:		
2011	**$ 1,235,447**	**$ 1,350,237**
2010	$ 1,224,398	$ 1,258,428

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

10. 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 may enter 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 Florida 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 two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *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 thousands)		
37,500	2017	-

*mmBtu - million British thermal units

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, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are $0.9 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 154**	$ 1,801	Liabilities from risk management activities	**$ 22,786**	$ 9,415
	Other deferred charges and assets	**44**	575	Other deferred credits and liabilities	**18,197**	4,193
Total derivatives designated as hedging instruments for regulatory purposes		**$ 198**	$ 2,376		**$ 40,983**	$ 13,608
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ -**	$ 4	Liabilities from risk management activities	**$ -**	$ -
Total		**$ 198**	$ 2,380		**$ 40,983**	$ 13,608

All derivative instruments are measured at fair value. See Note 9 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 thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (22,786)**	$ (9,415)	Other regulatory liabilities, current	**$ 154**	$1,801
	Other regulatory assets, deferred	**(18,197)**	(4,193)	Other regulatory liabilities, deferred	**44**	575
Total energy-related derivative gains (losses)		**$(40,983)**	$ (13,608)		**$ 198**	$2,376

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 thousands)				*(in thousands)*	
Interest rate derivatives	**$-**	$(1,405)	$2,934	Interest expense, net of amounts capitalized	**$(933)**	$(974)	$(1,085)

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 $4.6 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.

11. 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 Preference Stock
		(in thousands)	
March 2011	**$ 324,608**	**$ 32,044**	**$ 11,691**
June 2011	**399,265**	**67,387**	**33,352**
September 2011	**468,030**	**81,454**	**41,217**
December 2011	**327,909**	**43,839**	**18,745**
March 2010	$ 356,712	$ 52,430	$ 25,300
June 2010	403,171	65,066	32,317
September 2010	483,455	82,896	42,907
December 2010	346,871	46,408	20,987

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

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	2011	2010	2009	2008	2007
Operating Revenues (in thousands)	**$1,519,812**	$1,590,209	$1,302,229	$1,387,203	$1,259,808
Net Income After Dividends on Preference Stock (in thousands)	**$105,005**	$121,511	$111,233	$98,345	$84,118
Cash Dividends on Common Stock (in thousands)	**$110,000**	$104,300	$89,300	$81,700	$74,100
Return on Average Common Equity (percent)	**9.55**	11.69	12.18	12.66	12.32
Total Assets (in thousands)	**$3,871,881**	$3,584,939	$3,293,607	$2,879,025	$2,498,987
Gross Property Additions (in thousands)	**$337,830**	$285,379	$450,421	$390,744	$239,337
Capitalization (in thousands):					
Common stock equity	**$1,124,948**	$1,075,036	$1,004,292	$822,092	$731,255
Preference stock	**97,998**	97,998	97,998	97,998	97,998
Long-term debt	**1,235,447**	1,114,398	978,914	849,265	740,050
Total (excluding amounts due within one year)	**$2,458,393**	$2,287,432	$2,081,204	$1,769,355	$1,569,303
Capitalization Ratios (percent):					
Common stock equity	**45.8**	47.0	48.3	46.5	46.6
Preference stock	**4.0**	4.3	4.7	5.5	6.2
Long-term debt	**50.2**	48.7	47.0	48.0	47.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**378,248**	376,561	374,091	373,595	373,036
Commercial	**53,450**	53,263	53,272	53,548	53,838
Industrial	**273**	272	279	287	298
Other	**565**	562	512	499	491
Total	**432,536**	430,658	428,154	427,929	427,663
Employees (year-end)	**1,424**	1,330	1,365	1,342	1,324

	2011	2010	2009	2008	2007
Operating Revenues (in thousands):					
Residential	**$637,352**	$707,196	$588,073	$581,723	$537,668
Commercial	**408,389**	439,468	376,125	369,625	329,651
Industrial	**158,367**	157,591	138,164	165,564	135,179
Other	**4,382**	4,471	4,206	3,854	3,831
Total retail	**1,208,490**	1,308,726	1,106,568	1,120,766	1,006,329
Wholesale - non-affiliates	**133,555**	109,172	94,105	97,065	83,514
Wholesale - affiliates	**111,346**	110,051	32,095	106,989	113,178
Total revenues from sales of electricity	**1,453,391**	1,527,949	1,232,768	1,324,820	1,203,021
Other revenues	**66,421**	62,260	69,461	62,383	56,787
Total	**$1,519,812**	$1,590,209	$1,302,229	$1,387,203	$1,259,808
Kilowatt-Hour Sales (in thousands):					
Residential	**5,304,769**	5,651,274	5,254,491	5,348,642	5,477,111
Commercial	**3,911,399**	3,996,502	3,896,105	3,960,923	3,970,892
Industrial	**1,798,688**	1,685,817	1,727,106	2,210,597	2,048,389
Other	**25,430**	25,602	25,121	23,237	24,496
Total retail	**11,040,286**	11,359,195	10,902,823	11,543,399	11,520,888
Wholesale - non-affiliates	**2,012,986**	1,675,079	1,813,592	1,816,839	2,227,026
Wholesale - affiliates	**2,607,873**	2,436,883	870,470	1,871,158	2,884,440
Total	**15,661,145**	15,471,157	13,586,885	15,231,396	16,632,354
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.01**	12.51	11.19	10.88	9.82
Commercial	**10.44**	11.00	9.65	9.33	8.30
Industrial	**8.80**	9.35	8.00	7.49	6.60
Total retail	**10.95**	11.52	10.15	9.71	8.73
Wholesale	**5.30**	5.33	4.70	5.53	3.85
Total sales	**9.28**	9.88	9.07	8.70	7.23
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,028**	15,036	14,049	14,274	14,755
Residential Average Annual Revenue Per Customer	**$1,685**	$1,882	$1,572	$1,552	$1,448
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,663**	2,663	2,659	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,485**	2,544	2,310	2,360	2,215
Summer	**2,527**	2,519	2,538	2,533	2,626
Annual Load Factor (percent)	**54.5**	56.1	53.8	56.7	55.0
Plant Availability Fossil-Steam (percent)	**84.7**	94.7	89.7	88.6	93.4
Source of Energy Supply (percent):					
Coal	**49.4**	64.6	61.7	77.3	81.8
Gas	**24.0**	17.8	28.0	15.3	13.6
Purchased power -					
From non-affiliates	**22.3**	13.2	2.2	2.6	1.6
From affiliates	**4.3**	4.4	8.1	4.8	3.0
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS

Mark A. Crosswhite
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2010

Allan G. Bense
Chairman and Chief Executive Officer
Bense Enterprises, Inc.
Panama City, Florida. Elected 2010

Deborah H. Calder
Senior Vice President, Greater Pensacola Operations
Navy Federal Credit Union
Pensacola, Florida. Elected 2010

William C. Cramer, Jr.
President
Bill Cramer Chevrolet Cadillac Buick GMC, Inc.
Panama City, Florida. Elected 2002

J. Mort O'Sullivan, III
Managing Member
Warren Averett O'Sullivan Creel
Pensacola, Florida. Elected 2010

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

Winston E. Scott
Dean, College of Aeronautics
Florida Institute of Technology
Melbourne, Florida. Elected 2003

OFFICERS

Mark A. Crosswhite
President and Chief Executive Officer
7 Years of Service

Michael L. Burroughs
Vice President – Senior Production Officer
20 Years of Service

P. Bernard Jacob
Vice President – Customer Operations
29 Years of Service

Richard S. Teel
Vice President and Chief Financial Officer
12 Years of Service

Bentina C. Terry
Vice President – External Affairs and Corporate Services
10 Years of Service

Connie J. Erickson
Comptroller
9 Years of Service

Susan D. Ritenour
Secretary and Treasurer
30 Years of Service

Terry A. Davis
Assistant Secretary and Assistant Treasurer
25 Years of Service

Stacy R. Kilcoyne
Vice President
34 Years of Service

Melissa K. Caen
Assistant Secretary and Assistant Treasurer
5 Years of Service

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

Profile
The Company operates a vertically integrated utility providing electricity to both retail customers in northwest Florida and to wholesale customers in the Southeast. The Company sells electricity to approximately 430,000 customers within its service area of approximately 7,500 square miles within the northwestern portion of the State of Florida. In 2011, retail energy sales accounted for 70 percent of the Company's total sales of 15.7 billion kilowatt-hours.

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

Registrar, Transfer Agent, and Dividend Paying Agent
Preference Stock
Computershare Shareowner Services, LLC
480 Washington Boulevard
Jersey City, NJ 07310-1900
(800) 554-7626

www.bnymellon.com/shareowner/equityaccess

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
The Bank of New York Mellon
Global Corporate Trust
900 Ashford Center North, Suite 425
Atlanta, Georgia 30338

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

Form 10-K
A copy of 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 at the mailing address below:

Corporate Office
Principal Address & Deliveries:
Gulf Power Company
500 Bayfront Parkway
Pensacola, FL 32520
(850) 444-6111

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

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

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
Pensacola, FL 32591-2950

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