GULF POWER COMPANY

2012 ANNUAL REPORT

GULF POWER

A SOUTHERN COMPANY

CONTENTS

Gulf Power Company 2012 Annual Report

SUMMARY

	2012	2011	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,439,762**	**$1,519,812**	(5.3)
Operating expenses	**1,171,568**	**1,295,088**	(9.5)
Net income after dividends on preference stock	**125,932**	**105,005**	19.9
Gross property additions	**325,237**	**337,830**	(3.7)
Total assets	**4,177,402**	**3,871,881**	7.9
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**10,662,633**	**11,040,286**	(3.4)
Sales for resale - non-affiliates	**977,395**	**2,012,986**	(51.4)
Sales for resale – affiliates	**4,369,964**	**2,607,873**	67.6
Total	**16,009,992**	**15,661,145**	2.2
Customers served at year-end	**434,571**	**432,586**	0.5
Peak-hour demand, net *(in megawatts)*	**2,344**	**2,527**	(7.2)
Capitalization Ratios *(percent)*:			
Common stock equity	**47.9**	**45.8**	
Preference stock	**4.0**	**4.0**	
Long-term debt (excluding amounts due within one year)	**48.1**	**50.2**	
Return on Average Common Equity *(percent)*	**10.92**	**9.55**	

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2012 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, 2012.

S. W. Connally, Jr.
President and Chief Executive Officer

Richard S. Teel
Vice President and Chief Financial Officer

February 27, 2013

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, 2012 and 2011, 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, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages 27 to 67) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2012 Annual Report

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

On March 12, 2012, the Florida Public Service Commission (PSC) approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail return on equity (ROE) is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Key Performance Indicators

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 customer satisfaction. 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 2012 Peak Season EFOR 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. The transmission system performance for 2012 did not meet the target for these reliability measures. The distribution system performance for 2012 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 Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**4.99% or less**	**0.67%**
Net Income After Dividends on Preference Stock	**$120.7 million**	**$125.9 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 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 2012 net income after dividends on preference stock was $125.9 million, an increase of $20.9 million from the previous year. The increase in net income after dividends on preference stock in 2012 was primarily due to higher revenues due to increases in retail base rates and higher wholesale capacity revenues from non-affiliates in 2012. These increases were partially offset by milder weather in 2012, a decrease in retail energy sales in 2012 due to a decrease in customer usage, and a decrease in allowance for funds used during construction (AFUDC) equity, which is non-taxable.

In 2011, net income after dividends on preference stock was $105.0 million, a decrease of $16.5 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.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	**2012**	2011
		(in millions)	
Operating revenues	**$ 1,439.7**	**$ (80.1)**	$ (70.4)
Fuel	**544.9**	**(117.4)**	(80.0)
Purchased power	**74.1**	**(16.4)**	(6.7)
Other operations and maintenance	**314.2**	**2.8**	30.7
Depreciation and amortization	**141.0**	**11.4**	8.2
Taxes other than income taxes	**97.3**	**(3.9)**	(0.5)
Total operating expenses	**1,171.5**	**(123.5)**	(48.3)
Operating income	**268.2**	**43.4**	(22.1)
Total other income and (expense)	**(56.9)**	**(4.6)**	(4.6)
Income taxes	**79.2**	**17.9**	(10.2)
Net income	**132.1**	**20.9**	(16.5)
Dividends on preference stock	**6.2**	**—**	—
Net income after dividends on preference stock	**$ 125.9**	**$ 20.9**	$ (16.5)

Operating Revenues

Operating revenues for 2012 were $1.44 billion, reflecting a decrease of $80.1 million from 2011. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	**$ 1,208.5**	$ 1,308.7
Estimated change in –		
Rates and pricing	**62.7**	2.0
Sales growth (decline)	**(5.5)**	3.9
Weather	**(10.7)**	(17.8)
Fuel and other cost recovery	**(110.5)**	(88.3)
Retail — current year	**1,144.5**	1,208.5
Wholesale revenues –		
Non-affiliates	**106.9**	133.6
Affiliates	**123.6**	111.3
Total wholesale revenues	**230.5**	244.9
Other operating revenues	**64.7**	66.4
Total operating revenues	**$ 1,439.7**	$ 1,519.8
Percent change	**(5.3)%**	(4.4)%

Retail revenues decreased $64.0 million, or 5.3%, in 2012 compared to 2011 primarily as a result of lower fuel revenues due to lower natural gas prices and lower energy sales due to milder weather in 2012 compared to 2011, partially offset by higher revenues resulting from increases in retail base rates. 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. 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 higher revenues due to increases in retail base rates and revenues associated with higher recoverable costs under the Company's energy conservation cost recovery clause, partially offset by a decrease in revenues associated with lower recoverable costs under the Company's environmental cost recovery clause. 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.

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. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

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

	2012	2011	2010
		(in thousands)	
Unit power sales –			
Capacity	**$ 56,379**	$ 52,507	$ 33,482
Energy	**16,520**	44,227	31,379
Total	**72,899**	96,734	64,861
Other power sales –			
Capacity and other	**11,795**	10,717	11,158
Energy	**22,187**	26,104	33,153
Total	**33,982**	36,821	44,311
Total non-affiliated	**$ 106,881**	$ 133,555	$ 109,172

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

Revenues from unit power sales decreased $23.8 million, or 24.6%, in 2012 primarily due to a 62.6% decrease in energy revenues resulting from a 65.2% decrease in kilowatt-hour (KWH) sales as a result of less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads, partially offset by a 7.4% increase in capacity revenues related to higher capacity rates. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. Revenues from other power sales decreased $2.8 million, or 7.7%, in 2012 primarily due to decreased energy revenues resulting from a 16.5% decrease in energy rates, partially offset by a 10.1% increase in capacity revenues related to higher capacity rates. 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 in 2010. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in 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.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These 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. In 2012, wholesale revenues from sales to affiliates increased $12.3 million from the prior period primarily due to higher energy revenues related to a 67.6% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 33.8% decrease in the price of energy in 2012. In 2011, wholesale revenues from sales to affiliates increased $1.3 million from the prior period primarily due to higher energy revenues related to a 7.0% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 5.2% decrease in the price of energy in 2011.

Other operating revenues decreased $1.7 million, or 2.5%, in 2012 primarily due to a $3.0 million decrease in franchise fees, partially offset by a $2.0 million increase in revenues from other energy services. 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. 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 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	**2012**	2011	**2012**	2011
	(in millions)				
Residential	**5,054**	**(4.7)%**	(6.1)%	**(0.2)%**	0.5%
Commercial	**3,859**	**(1.4)**	(2.1)	**(0.5)**	—
Industrial	**1,725**	**(4.1)**	6.7	**(4.1)**	6.7
Other	**25**	**(0.6)**	(0.7)	**(0.6)**	(0.7)
Total retail	**10,663**	**(3.4)**	(2.8)	**(0.9)%**	1.3%
Wholesale					
Non-affiliates	**977**	**(51.5)**	20.2		
Affiliates	**4,370**	**67.6**	7.0		
Total wholesale	**5,347**	**15.7**	12.4		
Total energy sales	**16,010**	**2.2 %**	1.2 %		

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

Residential KWH sales and commercial KWH sales decreased in 2012 compared to 2011 primarily due to milder weather in 2012 compared to 2011. Weather-adjusted 2012 KWH sales to residential and commercial customers remained relatively flat as compared to 2011. 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.

Industrial KWH sales decreased 4.1% in 2012 compared to 2011 primarily due to increased customer co-generation due to the lower cost of natural gas and changes in customer production levels. 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.

Wholesale KWH sales to non-affiliates decreased 51.5% in 2012 compared to 2011 primarily resulting from less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads. 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 affiliates increased 67.6% and 7.0% in 2012 and 2011, respectively, compared to the prior periods primarily resulting from the availability of the Company's lower priced generation resources to serve affiliate demand.

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 generation and purchased power were as follows:

	2012	2011	2010
Total generation *(millions of KWHs)*	**9,648**	12,035	13,440
Total purchased power *(millions of KWHs)*	**6,952**	4,349	2,858
Sources of generation *(percent)* –			
Coal	**60**	67	78
Gas	**40**	33	22
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.42**	4.97	5.10
Gas	**3.96**	4.06	4.68
Average cost of fuel, generated *(cents per net KWH)*	**4.23**	4.67	5.01
Average cost of purchased power *(cents per net KWH*)*	**3.03**	4.39	5.82

* 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 $619.0 million in 2012, a decrease of $133.8 million, or 17.8%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $129.9 million decrease in the average cost of fuel and purchased power and a $118.2 million decrease related to the volume of KWHs generated. The decrease was partially offset by a $114.3 million increase related to the volume of KWHs purchased. 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 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.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

Fuel

Fuel expense was $544.9 million in 2012, a decrease of $117.4 million, or 17.7%, from the prior year costs. The decrease was primarily due to a higher utilization of lower cost natural gas-fired sources, a 2.5% decrease in the average cost of natural gas per KWH generated, and a 19.8% decrease in KWHs generated as a result of displacement of coal-fired generation by energy purchases and lower demand related to milder weather. These decreases were partially offset by a 59.8% increase in KWHs purchased. Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. The 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.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $51.4 million in 2012, an increase of $2.5 million, or 5.2%, from the prior year. The increase was due to a $2.7 million increase in energy costs, partially offset by a $0.2 million decrease in capacity costs. The increase in energy costs was due to an increase in the volume of KWHs purchased, partially offset by a lower average cost per KWH. In 2011, purchased power expense from non-affiliates was $48.9 million, an increase of $7.6 million, or 18.4%, from the prior year. The increase was due to a $7.2 million increase in energy costs and a $0.4 million increase in capacity costs.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $22.7 million in 2012, a decrease of $18.9 million, or 45.5%, from the prior year. The decrease was due to a $19.1 million decrease in energy costs, partially offset by a $0.2 million increase in capacity costs. The decrease in energy costs was due to a decrease in the volume of KWHs purchased and a lower cost per KWH purchased. In 2011, purchased power expense from affiliates was $41.6 million, a decrease of $14.3 million, or 25.6%, from the prior year. The decrease was due to decreases of $9.0 million in energy costs and $5.3 million in capacity costs.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $2.8 million, or 0.9%, compared to the prior year primarily due to increases of $6.2 million in marketing programs and $3.0 million for transmission service related to a third party power purchase agreement (PPA), partially offset by a $6.9 million decrease in routine and planned outage maintenance expense at generation facilities. The increased expense from transmission service did not have a significant impact on earnings since the expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. The increased expense from marketing programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. 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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" and "–Energy Conservation Cost Recovery" herein and Note 1 to the financial statements under "Affiliate Transactions" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $11.4 million, or 8.8%, in 2012 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities. 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 at generation facilities and other net additions to transmission and distribution facilities.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $3.9 million, or 3.9%, in 2012 compared to the prior year primarily due to a $6.1 million decrease in gross receipts taxes and franchise fees, partially offset by a $1.3 million increase in property taxes and a $0.7 million increase in payroll 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. 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 decreased $4.7 million, or 47.3%, in 2012 compared to the prior year primarily due to an adjustment related to deferred future generation carrying costs and the completion of construction projects related to environmental control projects at generation facilities. 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 generation facilities. 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 $2.1 million, or 3.6%, in 2012 compared to the prior year primarily due to increases in long-term debt levels. 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. The increase was partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects.

Income Taxes

Income taxes increased $17.9 million, or 29.3%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable, and a decrease in state tax credits. Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. 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 territory. 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.

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. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. 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. In May 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. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. 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 2012, the Company had invested approximately $1.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $70 million, $141 million, and $136 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $644 million from 2013 through 2015, with annual totals of approximately $158 million, $319 million, and $167 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change 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. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

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 air quality, water, coal combustion byproducts, global climate change, 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 has spent approximately $1.1 billion in reducing and 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 National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, 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 nitrogen oxide (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. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to 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, unless a one-year compliance extension is granted by the state or local air permitting agency. Mississippi Power Company (Mississippi Power) has received this one-year extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Florida, Georgia, and Mississippi) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

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, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. 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.

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.

Water Quality

In April 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 entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. 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 propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced 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 that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology 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 FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015. See also 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. 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 continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 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. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

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 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 FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding estimated compliance costs for 2013 through 2015. See also 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 other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted 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

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including 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 EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 11 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 8 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.

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 March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, 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 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

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 a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, 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, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, 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 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects 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, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. 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, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. 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, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Income Tax Matters

Bonus Depreciation

In 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 production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $30 million and $35 million in 2013.

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, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, 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 any requirement to refund these regulatory 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

In November 2012, the Company began using automated meter readings to measure unbilled KWH sales for energy delivered through month-end. As of December 31, 2012, measured unbilled KWH sales represented approximately 90% of total unbilled KWH sales. Increased usage of actual data to compute unbilled revenues reduces the impact that estimates could have on the Company's results of operations; therefore, the Company no longer considers unbilled revenue a critical accounting estimate.

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 $1.3 million or less change in total annual benefit expense and an $18 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. 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 2013 through 2015, 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 are primarily 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 increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $13.4 million to the qualified pension plan.

Net cash provided from operating activities totaled $419.2 million in 2012, an increase of $43.0 million from 2011, primarily due to an increase in deferred income taxes primarily related to bonus depreciation, partially offset by decreases in the cash provided from prepaid income taxes, fossil fuel stock, and the recovery of fuel costs. Net cash provided from operating activities totaled $376.2 million in 2011, an increase of $108.4 million from 2010, primarily due to increases in the recovery of fuel costs and prepaid income taxes, primarily due to bonus depreciation.

Net cash used for investing activities totaled $348.6 million, $343.5 million, and $308.4 million for 2012, 2011, and 2010, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $325.2 million, $337.8 million, and $285.4 million for 2012, 2011, and 2010, 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 $55.8 million and $31.8 million in 2012 and 2011, respectively. Net cash provided from financing activities was $48.4 million in 2010. The 2012 and 2011 decreases in cash from financing activities were primarily due to short-term debt payments, long-term debt redemptions, and payment of common stock dividends, partially offset by common stock and long-term debt issuances. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2012 include an increase of $219.5 million in property, plant, and equipment, primarily due to the addition of environmental control projects at generation facilities, an increase of $190.0 million in accumulated deferred income taxes, primarily related to bonus depreciation, an increase in common stock, without par value due to the issuance of common stock to Southern Company for $40 million and an increase in other regulatory assets, deferred and other deferred credits and liabilities of $49.2 million and $44.2 million, respectively, primarily due to increases in PPAs' deferred capacity expense.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.5% in 2012 and 43.7% in 2011. 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, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend on regulatory approval, prevailing market conditions, 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 in the Southern Company system.

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, 2012, the Company had approximately $32.2 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$80	$195	$275	$275	$45	$—	$45	$35

(a) No credit arrangements expire after 2014.

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 contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. 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, 2012, the Company had $69 million of outstanding 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 were as follows:

	Short-term Debt at the End of the Period [a]		Short-term Debt During the Period [b]		
	Amount Outstanding	**Weighted Average Interest Rate**	**Average Outstanding**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding**
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	$ 124	0.3%	$ 69	0.3%	$ 124
December 31, 2011:					
Commercial paper	$ 111	0.2%	$ 53	0.2%	$ 111
Short-term bank debt	—	N/A	4	1.3%	30
Total	$ 111	0.2%	$ 57	0.3%	
December 31, 2010:					
Commercial paper	$ 92	0.3%	$ 44	0.3%	$ 108

(a) Excludes notes payable related to other energy service contracts of $3.2 million, $3.6 million, and $1.2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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 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. Subsequent to December 31, 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.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used by the Company for the redemption in June 2012 of all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project) due September 1, 2028.

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, 2012 were as follows:

Credit Ratings	**Maximum Potential Collateral Requirements**
	(in millions)
At BBB- and/or Baa3	$ 117
Below BBB- and/or Baa3	489

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 and the variable rate pollution control revenue bond 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 that has not been hedged at January 1, 2013 was 0.13%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $693,000 at January 1, 2013. 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:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (41)**	$ (11)
Contracts realized or settled	**30**	11
Current period changes[(a)]	**(12)**	(41)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (23)**	$ (41)

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

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	**$ 17**	$ (28)
Natural gas options	**1**	(2)
Other energy-related derivatives	**—**	—
Total changes	**$ 18**	$ (30)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**71**	35
Commodity – Natural gas options	**—**	3
Total hedge volume	**71**	38

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.32 per mmBtu as of December 31, 2012 and $1.14 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2012 and 2011, 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, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	**$ —**	**$ —**	**$ —**
Level 2	**(23)**	**(15)**	**(8)**
Level 3	**—**	**—**	**—**
Fair value of contracts outstanding at end of period	**$ (23)**	**$ (15)**	**$ (8)**

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, Inc. and Standard & Poor's Ratings Services, 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.

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 as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 177	$ 141	$ 138
Existing environmental statutes and regulations, including the MATS rule	158	319	167
Total construction program base level capital investment	**$ 335**	**$ 460**	**$ 305**
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$ —	$ 18	$ 70

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

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 and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; 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

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in thousands)			
Long-term debt[a] –						
Principal	$ 60,000	$ 75,000	$ 195,000	$ 923,955	$ —	$ 1,253,955
Interest	55,095	101,295	91,790	628,206	—	876,386
Financial derivative obligations[b]	16,529	10,209	374	—	—	27,112
Preference stock dividends[c]	6,203	12,405	12,405	—	—	31,013
Operating leases	18,930	18,702	2,128	—	—	39,760
Unrecognized tax benefits[d]	—	—	—	—	5,007	5,007
Purchase commitments –						
Capital[e]	313,952	764,631	—	—	—	1,078,583
Fuel[f]	347,607	459,534	216,967	160,095	—	1,184,203
Purchased power[g]	49,015	160,304	184,613	500,398	—	894,330
Other[h]	15,862	32,923	19,194	15,846	—	83,825
Pension and other postretirement benefit plans[i]	3,928	8,559	—	—	—	12,487
Total	$ 887,121	$1,643,562	$ 722,471	$2,228,500	$ 5,007	$ 5,486,661

(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, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) 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 $5.0 million in unrecognized tax benefits 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 under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $18 million and $70 million for years 2014 and 2015, respectively. These amounts also exclude capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

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

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) 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 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, 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, 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), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- 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, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,144,471**	$ 1,208,490	$ 1,308,726
Wholesale revenues, non-affiliates	**106,881**	133,555	109,172
Wholesale revenues, affiliates	**123,636**	111,346	110,051
Other revenues	**64,774**	66,421	62,260
Total operating revenues	**1,439,762**	1,519,812	1,590,209
Operating Expenses:			
Fuel	**544,936**	662,283	742,322
Purchased power, non-affiliates	**51,421**	48,882	41,278
Purchased power, affiliates	**22,665**	41,612	55,948
Other operations and maintenance	**314,195**	311,358	280,585
Depreciation and amortization	**141,038**	129,651	121,498
Taxes other than income taxes	**97,313**	101,302	101,778
Total operating expenses	**1,171,568**	1,295,088	1,343,409
Operating Income	**268,194**	224,724	246,800
Other Income and (Expense):			
Allowance for equity funds used during construction	**5,221**	9,914	7,213
Interest income	**1,408**	54	123
Interest expense, net of amounts capitalized	**(60,250)**	(58,150)	(51,897)
Other income (expense), net	**(3,227)**	(4,066)	(3,011)
Total other income and (expense)	**(56,848)**	(52,248)	(47,572)
Earnings Before Income Taxes	**211,346**	172,476	199,228
Income taxes	**79,211**	61,268	71,514
Net Income	**132,135**	111,208	127,714
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$ 125,932**	$ 105,005	$ 121,511

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Net Income	**$ 132,135**	$ 111,208	$ 127,714
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(542), respectively	**—**	—	(863)
Reclassification adjustment for amounts included in net income, net of tax of $360, $360, and $376, respectively	**573**	573	598
Total other comprehensive income (loss)	**573**	573	(265)
Comprehensive Income	**$ 132,708**	$ 111,781	$ 127,449

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	**$ 132,135**	$ 111,208	$ 127,714
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**147,723**	135,790	127,897
Deferred income taxes	**174,305**	63,228	82,681
Allowance for equity funds used during construction	**(5,221)**	(9,914)	(7,213)
Pension, postretirement, and other employee benefits	**(8,109)**	(356)	(23,964)
Stock based compensation expense	**1,647**	1,318	1,101
Hedge settlements	**—**	—	1,530
Other, net	**4,518**	(8,258)	(4,126)
Changes in certain current assets and liabilities —			
-Receivables	**8,713**	21,518	(36,687)
-Prepayments	**417**	10,150	(10,796)
-Fossil fuel stock	**(6,144)**	17,519	15,766
-Materials and supplies	**(3,035)**	(5,073)	(6,251)
-Prepaid income taxes	**355**	26,901	(29,630)
-Other current assets	**—**	40	55
-Accounts payable	**(5,195)**	(2,528)	15,683
-Accrued taxes	**(4,705)**	1,475	1,427
-Accrued compensation	**481**	25	5,122
-Over recovered regulatory clause revenues	**(10,858)**	10,247	3,192
-Other current liabilities	**(7,837)**	2,937	4,279
Net cash provided from operating activities	**419,190**	376,227	267,780
Investing Activities:			
Property additions	**(313,257)**	(324,372)	(285,793)
Distribution of restricted cash from pollution control revenue bonds	**—**	—	6,347
Cost of removal net of salvage	**(28,993)**	(14,471)	(1,145)
Construction payables	**1,161**	2,902	(21,581)
Payments pursuant to long-term service agreements	**(8,119)**	(8,007)	(6,011)
Other investing activities	**656**	420	(262)
Net cash used for investing activities	**(348,552)**	(343,528)	(308,445)
Financing Activities:			
Increase (decrease) in notes payable, net	**16,075**	21,324	4,451
Proceeds —			
Common stock issued to parent	**40,000**	50,000	50,000
Capital contributions from parent company	**2,106**	2,101	2,242
Pollution control revenue bonds	**13,000**	—	21,000
Senior notes	**100,000**	125,000	300,000
Redemptions —			
Pollution control revenue bonds	**(13,000)**	—	—
Senior notes	**(91,363)**	(608)	(215,515)
Other long-term debt	**—**	(110,000)	—
Payment of preference stock dividends	**(6,203)**	(6,203)	(6,203)
Payment of common stock dividends	**(115,800)**	(110,000)	(104,300)
Other financing activities	**(614)**	(3,419)	(3,253)
Net cash provided from (used for) financing activities	**(55,799)**	(31,805)	48,422
Net Change in Cash and Cash Equivalents	**14,839**	894	7,757
Cash and Cash Equivalents at Beginning of Year	**17,328**	16,434	8,677
Cash and Cash Equivalents at End of Year	**$ 32,167**	$ 17,328	$ 16,434
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $2,500, $3,951 and $2,875 capitalized, respectively)	**$ 58,255**	$ 55,486	$ 42,521
Income taxes (net of refunds)	**(96,639)**	(26,345)	17,224
Noncash transactions — accrued property additions at year-end	**27,369**	19,439	14,475

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

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Assets	**2012**	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 32,167**	$ 17,328
Receivables —		
Customer accounts receivable	**58,449**	72,754
Unbilled revenues	**53,363**	49,921
Under recovered regulatory clause revenues	**6,138**	5,530
Other accounts and notes receivable	**11,859**	13,350
Affiliated companies	**13,624**	14,844
Accumulated provision for uncollectible accounts	**(1,490)**	(1,962)
Fossil fuel stock, at average cost	**153,710**	147,567
Materials and supplies, at average cost	**53,365**	49,781
Other regulatory assets, current	**30,576**	35,849
Prepaid expenses	**62,877**	28,327
Other current assets	**2,690**	2,051
Total current assets	**477,328**	435,340
Property, Plant, and Equipment:		
In service	**4,260,844**	3,846,446
Less accumulated provision for depreciation	**1,168,055**	1,124,291
Plant in service, net of depreciation	**3,092,789**	2,722,155
Construction work in progress	**136,062**	287,173
Total property, plant, and equipment	**3,228,851**	3,009,328
Other Property and Investments	**15,737**	16,394
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**50,139**	48,210
Other regulatory assets, deferred	**372,294**	323,116
Other deferred charges and assets	**33,053**	39,493
Total deferred charges and other assets	**455,486**	410,819
Total Assets	**$ 4,177,402**	$ 3,871,881

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

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	**2012**	2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 60,000**	$ —
Notes payable	**127,002**	114,507
Accounts payable —		
Affiliated	**66,161**	54,874
Other	**54,551**	63,265
Customer deposits	**34,749**	35,779
Accrued taxes —		
Accrued income taxes	**45**	1,362
Other accrued taxes	**7,036**	12,114
Accrued interest	**12,364**	14,018
Accrued compensation	**14,966**	14,485
Other regulatory liabilities, current	**25,887**	35,639
Liabilities from risk management activities	**16,529**	22,786
Other current liabilities	**19,930**	22,916
Total current liabilities	**439,220**	391,745
Long-Term Debt (See accompanying statements)	**1,185,870**	1,235,447
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**648,952**	458,978
Accumulated deferred investment tax credits	**5,408**	6,760
Employee benefit obligations	**126,871**	109,740
Other cost of removal obligations	**213,413**	214,598
Other regulatory liabilities, deferred	**47,863**	44,843
Other deferred credits and liabilities	**231,065**	186,824
Total deferred credits and other liabilities	**1,273,572**	1,021,743
Total Liabilities	**2,898,662**	2,648,935
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,180,742**	1,124,948
Total Liabilities and Stockholder's Equity	**$ 4,177,402**	$ 3,871,881
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

	2012	2011	2012	2011
	(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		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**615,000**	606,363		
Total long-term notes payable	**945,000**	936,363		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	239,625		
Variable rates (0.13% to 0.17% at 1/1/13) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	308,955		
Unamortized debt discount	**(8,085)**	(9,871)		
Total long-term debt (annual interest requirement — $55.1 million)	**1,245,870**	1,235,447		
Less amount due within one year	**60,000**	—		
Long-term debt excluding amount due within one year	**1,185,870**	1,235,447	**48.1%**	50.2%
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 — $6.2 million)	**97,998**	97,998	**4.0**	4.0
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized - 20,000,000 shares				
Outstanding - 2012: 4,542,717 shares				
- 2011: 4,142,717 shares	**393,060**	353,060		
Paid-in capital	**547,798**	542,709		
Retained earnings	**241,465**	231,333		
Accumulated other comprehensive income (loss)	**(1,581)**	(2,154)		
Total common stockholder's equity	**1,180,742**	1,124,948	**47.9**	45.8
Total Capitalization	**$ 2,464,610**	$ 2,458,393	**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, 2012, 2011, and 2010
Gulf Power Company 2012 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, 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**
Net income after dividends on preference stock	**—**	**—**	**—**	**125,932**	**—**	**125,932**
Issuance of common stock	**400**	**40,000**	**—**	**—**	**—**	**40,000**
Capital contributions from parent company	**—**	**—**	**5,089**	**—**	**—**	**5,089**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**573**	**573**
Cash dividends on common stock	**—**	**—**	**—**	**(115,800)**	**—**	**(115,800)**
Balance at December 31, 2012	**4,543**	**$ 393,060**	**$ 547,798**	**$ 241,465**	**$ (1,581)**	**$ 1,180,742**

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, as well as 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 the Southern Company system'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 $95.9 million, $97.4 million, and $98.8 million during 2012, 2011, and 2010, 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 $6.9 million, $6.7 million, and $8.9 million and Mississippi Power $21.1 million, $23.4 million, and $25.0 million in 2012, 2011, and 2010, 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 $14.7 million, $14.3 million, and $14.5 million in 2012, 2011, and 2010, respectively, and fuel costs associated with the PPA were $2.6 million, $1.8 million, and $3.3 million in 2012, 2011, and 2010, 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, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" 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 in each of the years 2012, 2011, and 2010 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, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $136.7 million for the entire project. These costs began in July 2012 and will continue through 2023. The Company reimbursed Alabama Power $3.0 million in 2012 for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased 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 material services to or from affiliates in 2012 or 2010. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million.

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

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB 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:

	2012	2011	Note
	(in thousands)		
Deferred income tax charges	**$ 46,788**	$ 44,533	(a)
Deferred income tax charges — Medicare subsidy	**3,678**	4,005	(b)
Asset retirement obligations	**(5,793)**	(5,653)	(a,j)
Other cost of removal obligations	**(213,413)**	(214,598)	(a)
Deferred income tax credits	**(6,515)**	(8,113)	(a)
Loss on reacquired debt	**16,400**	14,437	(c)
Vacation pay	**9,238**	8,973	(d,j)
Under recovered regulatory clause revenues	**3,523**	3,133	(e)
Over recovered regulatory clause revenues	**(17,092)**	(27,950)	(e)
Property damage reserve	**(31,956)**	(30,473)	(f)
Fuel hedging (realized and unrealized) losses	**29,038**	43,071	(g,j)
Fuel hedging (realized and unrealized) gains	**(4,358)**	(197)	(g,j)
PPA charges	**137,568**	94,986	(j,k)
Generation site selection/evaluation costs	**1,344**	20,415	(l)
Other regulatory assets	**9,690**	1,675	(e,j)
Environmental remediation	**60,452**	61,625	(h,j)
PPA credits	**(7,502)**	(7,536)	(j,k)
Other regulatory liabilities	**(534)**	(798)	(f)
Retiree benefit plans, net	**141,429**	116,091	(i,j)
Total regulatory assets (liabilities), net	**$ 171,985**	$ 117,626	

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 assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(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 five 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 14 years. See Note 2 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. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

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

	2012	2011
	(in thousands)	
Generation	**$ 2,598,773**	$ 2,283,494
Transmission	**429,341**	368,542
Distribution	**1,069,065**	1,030,546
General	**161,379**	161,322
Plant acquisition adjustment	**2,286**	2,542
Total plant in service	**$ 4,260,844**	$ 3,846,446

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 other operations and 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 3.6% in 2012, 3.5% in 2011, and 3.5% in 2010. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. 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 its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

	2012	2011
	(in thousands)	
Balance at beginning of year	**$ 10,729**	$ 11,470
Liabilities incurred	**—**	106
Liabilities settled	**(107)**	(1,050)
Accretion	**507**	545
Cash flow revisions	**4,926**	(342)
Balance at end of year	**$ 16,055**	$ 10,729

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, AFUDC 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 6.72% for the year 2012. The average annual AFUDC rate was 7.65% for both 2011 and 2010. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 5.36%, 11.75%, and 7.39% for 2012, 2011, and 2010, 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 $48.0 million and $55.0 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 2012, 2011, and 2010. As of December 31, 2012 and 2011, the balance in the Company's property damage reserve totaled approximately $32.0 million and $30.5 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 $3.1 million and $2.7 million at December 31, 2012 and 2011, respectively. For 2012, $1.6 million and $1.5 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, 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. There were no liabilities in excess of the reserve balance at December 31, 2012 and 2011.

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, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, 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, 2012.

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, 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). In December 2012, the Company contributed $13.4 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. 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, 2013, 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.53%
Other postretirement benefit plans	**4.06**	4.88	5.41
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**8.02**	8.11	8.18

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, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,399	$ (2,897)
Service and interest costs	198	(169)

Pension Plans

The total accumulated benefit obligation for the pension plans was $371 million at December 31, 2012 and $321 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 352,834**	$ 316,286
Service cost	**9,101**	8,431
Interest cost	**17,199**	17,074
Benefits paid	**(14,046)**	(13,807)
Plan amendments	**426**	—
Actuarial loss	**47,987**	24,850
Balance at end of year	**413,501**	352,834
Change in plan assets		
Fair value of plan assets at beginning of year	**304,324**	307,828
Actual return on plan assets	**45,762**	9,552
Employer contributions	**14,220**	751
Benefits paid	**(14,046)**	(13,807)
Fair value of plan assets at end of year	**350,260**	304,324
Accrued liability	**$ (63,241)**	$ (48,510)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $393 million and $20 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets	**$ 139,261**	$ 115,853
Current liabilities, other	**(855)**	(794)
Employee benefit obligations	**(62,386)**	(47,716)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	**Estimated Amortization in 2013**
		(in thousands)	
Prior service cost	**$ 5,565**	$ 6,402	**$ 1,164**
Net (gain) loss	**133,696**	109,451	**8,385**
Other regulatory assets	**$ 139,261**	$ 115,853	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in thousands)
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
Net (gain) loss	**28,157**
Change in prior service costs	**426**
Reclassification adjustments:	
Amortization of prior service costs	**(1,262)**
Amortization of net gain (loss)	**(3,913)**
Total reclassification adjustments	**(5,175)**
Total change	**23,408**
Balance at December 31, 2012	**$ 139,261**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 9,101**	$ 8,431	$ 7,853
Interest cost	**17,199**	17,074	17,305
Expected return on plan assets	**(25,932)**	(27,232)	(24,695)
Recognized net (gain) loss	**3,913**	512	398
Net amortization	**1,262**	1,262	1,302
Net periodic pension cost	**$ 5,543**	$ 47	$ 2,163

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$ 15,767
2014	16,606
2015	17,427
2016	18,272
2017	19,383
2018 to 2022	113,108

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 70,923**	$ 69,617
Service cost	**1,167**	1,132
Interest cost	**3,367**	3,658
Benefits paid	**(3,854)**	(4,189)
Actuarial loss	**3,468**	292
Plan amendments	**—**	—
Retiree drug subsidy	**324**	413
Balance at end of year	**75,395**	70,923
Change in plan assets		
Fair value of plan assets at beginning of year	**14,978**	15,697
Actual return on plan assets	**2,131**	514
Employer contributions	**2,648**	2,543
Benefits paid	**(3,530)**	(3,776)
Fair value of plan assets at end of year	**16,227**	14,978
Accrued liability	**$ (59,168)**	$ (55,945)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Regulatory assets	**$ 2,169**	$ 239
Current liabilities, other	**(661)**	(624)
Employee benefit obligations	**(58,507)**	(55,321)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 324**	$ 510	**$ 186**
Net (gain) loss	**1,845**	(464)	**—**
Transition obligation	**—**	193	**—**
Regulatory assets (liabilities)	**$ 2,169**	$ 239	

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, 2012 and 2011 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
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	$ —
Net (gain) loss	**2,309**	**—**
Change in prior service costs/transition obligation	**—**	**—**
Reclassification adjustments:		
Amortization of transition obligation	**(193)**	**—**
Amortization of prior service costs	**(186)**	**—**
Amortization of net gain (loss)	**—**	**—**
Total reclassification adjustments	**(379)**	**—**
Total change	**1,930**	**—**
Balance at December 31, 2012	**$ 2,169**	**$ —**

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

	2012	2011	2010
		(in thousands)	
Service cost	**$ 1,167**	$ 1,132	$ 1,304
Interest cost	**3,367**	3,658	4,121
Expected return on plan assets	**(1,311)**	(1,445)	(1,481)
Net amortization	**379**	396	406
Net postretirement cost	**$ 3,602**	$ 3,741	$ 4,350

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)	
2013	$ 4,473	$ (488)	$ 3,985
2014	4,707	(537)	4,170
2015	4,903	(589)	4,314
2016	5,117	(643)	4,474
2017	5,211	(705)	4,506
2018 to 2022	26,913	(3,804)	23,109

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). 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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	**2012**	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**27%**	28%
International equity	24	**23**	24
Domestic fixed income	25	**29**	26
Special situations	3	**1**	—
Real estate investments	14	**13**	13
Private equity	9	**7**	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.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***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, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. 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.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 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, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	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*	$ 51,215	$ 29,499	$ —	$ 80,714
International equity*	40,166	43,120	—	83,286
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,724	—	22,724
Mortgage- and asset-backed securities	—	5,594	—	5,594
Corporate bonds	—	38,534	139	38,673
Pooled funds	—	17,581	—	17,581
Cash equivalents and other	208	24,148	—	24,356
Real estate investments	11,362	—	37,039	48,401
Private equity	—	—	26,129	26,129
Total	$ 102,951	$ 181,200	$ 63,307	$ 347,458

* 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, 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.

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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	**$ 34,989**	**$ 26,053**	$ 30,355	$ 28,727
Actual return on investments:				
Related to investments held at year end	**1,918**	**44**	3,021	(538)
Related to investments sold during the year	**132**	**1,396**	896	1,941
Total return on investments	**2,050**	**1,440**	3,917	1,403
Purchases, sales, and settlements	**—**	**(1,364)**	717	(4,077)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 37,039**	**$ 26,129**	$ 34,989	$ 26,053

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**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*	$ 2,290	$ 1,319	$ —	$ 3,609
International equity*	1,795	1,928	—	3,723
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,016	—	1,016
Mortgage- and asset-backed securities	—	250	—	250
Corporate bonds	—	1,722	6	1,728
Pooled funds	—	1,298	—	1,298
Cash equivalents and other	9	1,078	—	1,087
Real estate investments	508	—	1,667	2,175
Private equity	—	15	1,155	1,170
Total	$ 4,602	$ 8,626	$ 2,828	$ 16,056

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

As of December 31, 2011:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in 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.

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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$ 1,657**	**$ 1,232**	$ 1,452	$ 1,375
Actual return on investments:				
Related to investments held at year end	**107**	**(1)**	129	(26)
Related to investments sold during the year	**6**	**80**	42	77
Total return on investments	**113**	**79**	171	51
Purchases, sales, and settlements	**(103)**	**(156)**	34	(194)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 1,667**	**$ 1,155**	$ 1,657	$ 1,232

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 2012, 2011, and 2010 were $4.0 million, $3.7 million, and $3.6 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, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, 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.

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. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability 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. In May 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. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability 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, 2012, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $60.5 million. For 2012, approximately $2.6 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $57.9 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 March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, 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 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

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 a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, 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, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, 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 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects 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, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. 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, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. 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, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues 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, 2012, 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	$ 373,576 [(a)]	$ 277,440
Accumulated depreciation	117,181	165,120
Construction work in progress	8,763	69,774
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.3 million.

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

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. 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 current expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (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:

	2012	2011	2010
		(in thousands)	
Federal -			
Current	**$ (92,610)**	$ (1,548)	$ (14,115)
Deferred	**161,096**	56,087	77,452
	68,486	54,539	63,337
State -			
Current	**(2,484)**	(412)	2,948
Deferred	**13,209**	7,141	5,229
	10,725	6,729	8,177
Total	**$ 79,211**	$ 61,268	$ 71,514

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:

	2012	2011
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	**$ 696,502**	$ 496,392
Pension and other employee benefits	**28,579**	25,268
Regulatory assets associated with employee benefit obligations	**57,279**	44,871
Regulatory assets associated with asset retirement obligations	**6,502**	4,345
Other	**16,019**	14,804
Total	**804,881**	585,680
Deferred tax assets-		
Federal effect of state deferred taxes	**20,656**	16,684
Postretirement benefits	**17,905**	16,769
Fuel recovery clause	**6,922**	2,531
Pension and other employee benefits	**61,939**	49,116
Property reserve	**13,773**	13,159
Other comprehensive loss	**993**	1,353
Asset retirement obligations	**6,502**	4,345
Alternative minimum tax carryforward	**938**	7,151
Other	**28,273**	20,191
Total	**157,901**	131,299
Net deferred tax liabilities	**646,980**	454,381
Portion included in current assets (liabilities), net	**1,972**	4,597
Accumulated deferred income taxes	**$ 648,952**	$ 458,978

At December 31, 2012, the tax-related regulatory assets to be recovered from customers were $50.5 million. These assets are primarily 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.

At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $6.5 million. These liabilities are primarily 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 life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.4 million in 2012, $1.3 million in 2011, and $1.5 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 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 production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act 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:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.3**	2.5	2.7
Non-deductible book depreciation	**0.5**	0.5	0.3
Differences in prior years' deferred and current tax rates	**(0.2)**	(0.3)	(0.3)
AFUDC equity	**(0.9)**	(2.0)	(1.3)
Other, net	**(0.2)**	(0.2)	(0.5)
Effective income tax rate	**37.5%**	35.5%	35.9%

The increase in the 2012 effective tax rate is primarily the result of a decrease in AFUDC equity, which is not taxable, and a decrease in state tax credits.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $2.1 million, resulting in a balance of $5.0 million as of December 31, 2012.

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

	2012	2011	2010
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 2,892**	$ 3,870	$ 1,639
Tax positions from current periods	**2,630**	540	1,027
Tax positions from prior periods	**515**	(1,518)	1,204
Reductions due to settlements	**(1,030)**	—	—
Balance at end of year	**$ 5,007**	$ 2,892	$ 3,870

The tax positions increase from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. The tax positions increase from prior periods for 2012 also relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

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

	2012	2011	2010
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 45**	$ 1,804	$ 1,826
Tax positions not impacting the effective tax rate	**4,962**	1,088	2,044
Balance of unrecognized tax benefits	**$ 5,007**	$ 2,892	$ 3,870

The tax positions impacting the effective tax rate for 2012 relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in thousands)	
Interest accrued at beginning of year	**$ 283**	$ 210	$ 90
Interest reclassified due to settlements	**(283)**	—	—
Interest accrued during the year	**—**	73	120
Balance at end of year	**$ —**	$ 283	$ 210

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 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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, 2014. 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; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

Approximately $60 million will be required through December 31, 2013 to fund maturities of long-term debt.

Maturities from 2014 through 2017 applicable to total long-term debt are as follows: $75 million in 2014; $110 million in 2016; and $85 million in 2017. There are no scheduled maturities in 2015.

Senior Notes

At December 31, 2012 and 2011, the Company had a total of $945 million and $936.4 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totals approximately $41 million at December 31, 2012.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used to redeem all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, 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 and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2012 and 2011 was $309 million.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used in December 2012 to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project), due September 1, 2028.

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, 2012. 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 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. Subsequent to December 31, 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, 2012, committed credit arrangements with banks were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$ 80	$ 195	$ 275	$ 275	$ 45	$ —	$ 45	$ 35

(a) No credit arrangements expire after 2014.

During 2012, the Company renewed a $30 million credit arrangement and changed the terms of the credit arrangement so that it expires after two years instead of one year, which is reflected in the table above. The Company expects to renew its credit arrangements, as needed, prior to expiration. Of the $275 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $206 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of those credit arrangements with banks contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. At December 31, 2012, the Company was in compliance with these covenants.

In addition, the credit arrangements typically contain cross default provisions that 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 included in notes payable on the balance sheets were as follows:

	Short-term Debt at the End of the Period [a]	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2012:		
Commercial paper	$ 124	0.3%
December 31, 2011:		
Commercial paper	$ 111	0.2%

(a) Excludes notes payable related to other energy service contracts of $3.2 million and $3.6 million for the periods ended December 31, 2012 and 2011, respectively.

7. COMMITMENTS

Fuel and Purchased Power Agreements

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 which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $544.9 million, $662.3 million, and $742.3 million, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. 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. Capacity expense under purchased power agreements accounted for as operating leases was $24.6 million, $25.1 million, and $25.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum long-term commitments at December 31, 2012 were as follows:

	Operating Lease PPAs
	(in millions)
2013	$ 24.7
2014	52.9
2015	78.6
2016	78.7
2017	78.8
2018 and thereafter	428.1
Total	**$ 741.8**

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. Total rent expense was $20.1 million, $21.9 million, and $23.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum lease payments under operating leases at December 31, 2012 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2013	$ 18.6	$ 0.3	$ 18.9
2014	17.2	0.3	17.5
2015	1.1	0.1	1.2
2016	0.9	0.1	1.0
2017	1.0	0.1	1.1
2018 and thereafter	—	—	—
Total	**$ 38.8**	**$ 0.9**	**$ 39.7**

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

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, 2012, there were 218 current and former employees of the Company participating in the stock option program, and there were 39 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	**2012**	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2011	1,498,663	$ 33.75
Granted	244,607	44.43
Exercised	(353,749)	31.97
Cancelled	(606)	42.08
Outstanding at December 31, 2012	**1,388,915**	**$ 36.08**
Exercisable at December 31, 2012	**884,888**	**$ 34.02**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012, was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $9.7 million and $7.8 million, respectively.

As of December 31, 2012, there was $0.3 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, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.7 million, $0.7 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 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, 2012, 2011, and 2010 was $3.8 million, $3.2 million, and $1.6 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.5 million, $1.2 million, and $0.6 million for the years ended December 31, 2012, 2011, and 2010, 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. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate 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 following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2012**	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 66,662. During 2012, 29,444 performance share units were granted, 26,738 performance share units were vested, and 563 performance share units were forfeited resulting in 68,805 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 36,105 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.0 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.0 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted average period of approximately 11 months.

9. 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, 2012, 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, 2012:	**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	$ —	$ 4,358	$ —	$ 4,358
Cash equivalents	15,231	—	—	15,231
Total	$ 15,231	$ 4,358	$ —	$ 19,589
Liabilities:				
Energy-related derivatives	$ —	$ 27,112	$ —	$ 27,112

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

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, 2012 and 2011, 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, 2012:	*(in thousands)*			
Cash equivalents:				
Money market funds	$15,231	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$13,949	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, 2012 and 2011, 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:		
2012	**$ 1,245,870**	**$ 1,367,404**
2011	$ 1,235,447	$ 1,350,237

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

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 and are presented on a gross basis.

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, 2012, 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)		
70,510	2017	—

* mmBtu — million British thermal units

Interest Rate Derivatives

The Company may also enter 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, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $0.8 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, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 1,293**	$ 154	Liabilities from risk management activities	**$ 16,529**	$ 22,786
	Other deferred charges and assets	**3,065**	44	Other deferred credits and liabilities	**10,583**	18,197
Total derivatives designated as hedging instruments for regulatory purposes		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ —
Total		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983

All derivative instruments are measured at fair value. See Note 9 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (16,529)**	$ (22,786)	Other regulatory liabilities, current	**$ 1,293**	$ 154
	Other regulatory assets, deferred	**(10,583)**	(18,197)	Other regulatory liabilities, deferred	**3,065**	44
Total energy-related derivative gains (losses)		**$ (27,112)**	$ (40,983)		**$ 4,358**	$ 198

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were 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	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
		(in thousands)				*(in thousands)*	
Interest rate derivatives	**$ —**	$ —	$ (1,405)	Interest expense, net of amounts capitalized	**$ (933)**	$ (933)	$ (974)

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

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were 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, 2012, the fair value of derivative liabilities with contingent features was $4 million.

At December 31, 2012, 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 $15 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 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2012	**$ 316,245**	**$ 49,098**	**$ 20,666**
June 2012	**370,208**	**71,465**	**34,963**
September 2012	**421,819**	**93,813**	**47,754**
December 2012	**331,490**	**53,818**	**22,549**
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

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

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Gulf Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	**$ 1,439,762**	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Net Income After Dividends on Preference Stock (in thousands)	**$ 125,932**	$ 105,005	$ 121,511	$ 111,233	$ 98,345
Cash Dividends on Common Stock (in thousands)	**$ 115,800**	$ 110,000	$ 104,300	$ 89,300	$ 81,700
Return on Average Common Equity (percent)	**10.92**	9.55	11.69	12.18	12.66
Total Assets (in thousands)	**$ 4,177,402**	$ 3,871,881	$ 3,584,939	$ 3,293,607	$ 2,879,025
Gross Property Additions (in thousands)	**$ 325,237**	$ 337,830	$ 285,379	$ 450,421	$ 390,744
Capitalization (in thousands):					
Common stock equity	**$ 1,180,742**	$ 1,124,948	$ 1,075,036	$ 1,004,292	$ 822,092
Preference stock	**97,998**	97,998	97,998	97,998	97,998
Long-term debt	**1,185,870**	1,235,447	1,114,398	978,914	849,265
Total (excluding amounts due within one year)	**$ 2,464,610**	$ 2,458,393	$ 2,287,432	$ 2,081,204	$ 1,769,355
Capitalization Ratios (percent):					
Common stock equity	**47.9**	45.8	47.0	48.3	46.5
Preference stock	**4.0**	4.0	4.3	4.7	5.5
Long-term debt	**48.1**	50.2	48.7	47.0	48.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**379,922**	378,248	376,561	374,091	373,595
Commercial	**53,808**	53,450	53,263	53,272	53,548
Industrial	**264**	273	272	279	287
Other	**577**	565	562	512	499
Total	**434,571**	432,536	430,658	428,154	427,929
Employees (year-end)	**1,416**	1,424	1,330	1,365	1,342

SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
Gulf Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	**$ 609,454**	$ 637,352	$ 707,196	$ 588,073	$ 581,723
Commercial	**389,936**	408,389	439,468	376,125	369,625
Industrial	**140,490**	158,367	157,591	138,164	165,564
Other	**4,591**	4,382	4,471	4,206	3,854
Total retail	**1,144,471**	1,208,490	1,308,726	1,106,568	1,120,766
Wholesale — non-affiliates	**106,881**	133,555	109,172	94,105	97,065
Wholesale — affiliates	**123,636**	111,346	110,051	32,095	106,989
Total revenues from sales of electricity	**1,374,988**	1,453,391	1,527,949	1,232,768	1,324,820
Other revenues	**64,774**	66,421	62,260	69,461	62,383
Total	**$ 1,439,762**	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Kilowatt-Hour Sales (in thousands):					
Residential	**5,053,724**	5,304,769	5,651,274	5,254,491	5,348,642
Commercial	**3,858,521**	3,911,399	3,996,502	3,896,105	3,960,923
Industrial	**1,725,121**	1,798,688	1,685,817	1,727,106	2,210,597
Other	**25,267**	25,430	25,602	25,121	23,237
Total retail	**10,662,633**	11,040,286	11,359,195	10,902,823	11,543,399
Wholesale — non-affiliates	**977,395**	2,012,986	1,675,079	1,813,592	1,816,839
Wholesale — affiliates	**4,369,964**	2,607,873	2,436,883	870,470	1,871,158
Total	**16,009,992**	15,661,145	15,471,157	13,586,885	15,231,396
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.06**	12.01	12.51	11.19	10.88
Commercial	**10.11**	10.44	11.00	9.65	9.33
Industrial	**8.14**	8.80	9.35	8.00	7.49
Total retail	**10.73**	10.95	11.52	10.15	9.71
Wholesale	**4.31**	5.30	5.33	4.70	5.53
Total sales	**8.59**	9.28	9.88	9.07	8.70
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,303**	14,028	15,036	14,049	14,274
Residential Average Annual Revenue Per Customer	**$ 1,604**	$ 1,685	$ 1,882	$ 1,572	$ 1,552
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,663**	2,663	2,663	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,130**	2,485	2,544	2,310	2,360
Summer	**2,344**	2,527	2,519	2,538	2,533
Annual Load Factor (percent)	**56.3**	54.5	56.1	53.8	56.7
Plant Availability Fossil-Steam (percent)*	**82.5**	84.7	94.7	89.7	88.6
Source of Energy Supply (percent):					
Coal	**34.6**	49.4	64.6	61.7	77.3
Gas	**23.5**	24.0	17.8	28.0	15.3
Purchased power —					
From non-affiliates	**40.2**	22.3	13.2	2.2	2.6
From affiliates	**1.7**	4.3	4.4	8.1	4.8
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

DIRECTORS AND OFFICERS
Gulf Power Company 2012 Annual Report

DIRECTORS

S. W. Connally, Jr. (1)
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2012

Mark A. Crosswhite (2)
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
SVP, 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 (3)
Broker/President
Bill Pullum Realty, Inc.
Navarre, Florida. Elected 2001

Winston E. Scott
Senior Vice President for External Relations & Economic Development
Florida Institute of Technology
Melbourne, Florida. Elected 2003

OFFICERS

S. W. Connally, Jr. (1)
President and Chief Executive Officer
24 Years of Service

Mark A. Crosswhite (2)
President and Chief Executive Officer
8 Years of Service

Michael L. Burroughs
Vice President – Sr. Production Officer
21 Years of Service

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

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

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

Connie J. Erickson
Comptroller
10 Years of Service

Susan D. Ritenour
Secretary and Treasurer
31 Years of Service

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

Stacy R. Kilcoyne
Vice President
35 Years of Service

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

(1) Elected effective July 1, 2012.
(2) Resigned effective July 1, 2012.
(3) Retired effective May 14, 2012.

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Florida. The Company sells electricity to approximately 435,000 customers within its service area of approximately 7,500 square miles in the Florida panhandle. In 2012, retail energy sales accounted for 67 percent of the Company's total sales of 16 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
P.O. Box 43006
Providence, RI 02940-3006
(800) 554-7626

www.computershare.com/investor

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

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

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

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

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