GULF POWER COMPANY

2010 Annual Report

GULF POWER
A SOUTHERN COMPANY

CONTENTS

Gulf Power Company 2010 Annual Report

SUMMARY

	2010	2009	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,590,209**	**$1,302,229**	22.1
Operating expenses	**1,343,409**	**1,113,567**	20.6
Net income after dividends on preference stock	**121,511**	**111,233**	9.2
Gross property additions	**285,379**	**450,421**	(36.6)
Total assets	**3,584,939**	**3,293,607**	8.8
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**11,359,195**	**10,902,823**	4.2
Sales for resale - non-affiliates	**1,675,079**	**1,813,592**	(7.6)
Sales for resale – affiliates	**2,436,883**	**870,470**	180.0
Total	**15,471,157**	**13,586,885**	13.9
Customers served at year-end	**430,658**	**428,154**	0.6
Peak-hour demand, net *(in megawatts)*	**2,544**	**2,538**	0.2
Capitalization Ratios *(percent)*:			
Common stock equity	**47.0**	**48.3**	
Preference stock	**4.3**	**4.7**	
Long-term debt (excluding amounts due within one year)	**48.7**	**47.0**	
Return on Average Common Equity *(percent)*	**11.69**	**12.18**	

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Letter to Investors

Commitment is a promise

Total commitment. It is one of the three components of “Southern Style” — a deeply held core value at Gulf Power, and it is our promise to do everything to the best of our ability.

Total commitment to our customers. Customer service is paramount and the responsibility of all Gulf Power employees. Recently, we renewed our commitment to our customers and developed a comprehensive plan to enhance customer focus. Aimed at increasing customer value, our “Making a Difference” program makes us all accountable for providing exceptional service to our customers.

Total commitment to the environment. In 2010, two very significant environmental projects were completed.

Gulf Power’s Plant Crist began re-using millions of gallons of treated water from the Emerald Coast Utilities Authority’s new advanced wastewater treatment facility. The water is used in the scrubber process and for cooling. The beneficial partnership helps ECUA become a zero-discharge facility and greatly reduces the amount of water we use from the Escambia River. As a result of this project, Gulf Power Company and the Emerald Coast Utilities Authority were awarded the Sustainable Florida-Collins Center 2010 Best Practice Awards program by the State of Florida and also received recognition by the Southeastern Electric Exchange.

In addition, Gulf Power completed the company’s first wholly-owned landfill gas-to-energy facility in October. This plant, in partnership with Escambia County, is now producing enough renewable energy to power 900 homes.

Total commitment to you, our investors. Our commitment to you is to continue to maintain strong financial performance, financial integrity and a strong credit rating. Our board of directors continues to provide the leadership and support to meet the challenges we face.

Total commitment as your new President and CEO. Joining Gulf Power on January 1, 2011 is the highlight of my career. Congratulations to Susan Story who was named President and CEO of Southern Company Services. Thanks to her hard work and leadership, Gulf Power is a well-respected and admired company in our communities and throughout the state.

As we move forward, my overarching commitment to you is that we will continue to work every day to keep electricity affordable, reliable and environmentally responsible. Thank you for your support and confidence in Gulf Power Company.

Mark A. Crosswhite
President and Chief Executive Officer
April 1, 2011

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Gulf Power Company 2010 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, 2010.

Mark A. Crosswhite
President and Chief Executive Officer

Richard S. Teel
Vice President and Chief Financial Officer

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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 Southern Company) as of December 31, 2010 and 2009, 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, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such financial statements (pages 28 to 68) present fairly, in all material respects, the financial position of Gulf Power Company at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2011

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 rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, and storm restoration costs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 430,000 customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2010 Peak Season EFOR of 3.86% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2010 was better than the target for these reliability measures.

Net income after dividends on preference stock is the primary measure of the Company's financial performance. The performance for net income after dividends on preference stock in 2010 was above target. The Company's 2010 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2010 Target Performance	2010 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**5.06% or less**	**3.86%**
Net income after dividends on preference stock	**$116.8 million**	**$121.5 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis the Company places on these indicators as well as the commitment of employees to meet and exceed targets.

Earnings

The Company's 2010 net income after dividends on preference stock was $121.5 million, an increase of $10.3 million from the previous year. In 2009, net income after dividends on preference stock was $111.2 million, an increase of $12.9 million from the previous year. In 2008, net income after dividends on preference stock was $98.3 million, an increase of $14.2 million from the previous year. The increase in net income after dividends on preference stock in 2010 was primarily due to increased retail revenues due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010. The increases in revenues were partially offset by an increase in operations and maintenance expenses. The increase in net income after dividends on preference stock in 2009 was due primarily to increased allowance for funds used during construction (AFUDC) equity, which is non-taxable, and decreased interest expense, net of amounts capitalized, partially offset by unfavorable weather and a decline in sales. The increase in net income after dividends on preference stock in 2008 was due primarily to higher wholesale revenues from non-affiliates, increased AFUDC equity, and a gain on the sale of assets.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	**Increase (Decrease) from Prior Year**		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$ 1,590.2**	**$ 288.0**	$ (84.9)	$ 127.4
Fuel	**742.3**	**168.9**	(62.2)	62.2
Purchased power	**97.2**	**5.2**	(17.4)	37.9
Other operations and maintenance	**280.6**	**20.3**	(17.2)	7.1
Depreciation and amortization	**121.5**	**28.1**	8.6	(0.8)
Taxes other than income taxes	**101.8**	**7.3**	7.3	4.2
Total operating expenses	**1,343.4**	**229.8**	(80.9)	110.6
Operating income	**246.8**	**58.2**	(4.0)	16.8
Total other income and (expense)	**(47.6)**	**(29.4)**	15.8	6.7
Income taxes	**71.5**	**18.5**	(1.1)	7.0
Net income	**127.7**	**10.3**	12.9	16.5
Dividends on preference stock	**6.2**	**-**	-	2.3
Net income after dividends on preference stock	**$ 121.5**	**$ 10.3**	$ 12.9	$ 14.2

Operating Revenues

Operating revenues for 2010 were $1,590.2 million, reflecting an increase of $288.0 million from 2009. The following table summarizes the significant changes in operating revenues for the past three years:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$ 1,106.6**	$ 1,120.8	$ 1,006.3
Estimated change in –			
Rates and pricing	**72.7**	33.0	6.3
Sales growth (decline)	**(2.3)**	(5.7)	(4.6)
Weather	**18.7**	(4.5)	3.9
Fuel and other cost recovery	**113.0**	(37.0)	108.9
Retail – current year	**1,308.7**	1,106.6	1,120.8
Wholesale revenues –			
Non-affiliates	**109.2**	94.1	97.1
Affiliates	**110.0**	32.1	107.0
Total wholesale revenues	**219.2**	126.2	204.1
Other operating revenues	**62.3**	69.4	62.3
Total operating revenues	**$ 1,590.2**	$ 1,302.2	$ 1,387.2
Percent change	**22.1%**	(6.1)%	10.1%

Retail revenues increased $202.1 million, or 18.3%, in 2010, decreased $14.2 million, or 1.3%, in 2009, and increased $114.4 million, or 11.4%, in 2008.

Revenues associated with changes in rates and pricing include cost recovery provisions for energy conservation costs and environmental compliance costs. Annually, the Company petitions the Florida Public Service Commission (PSC) for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes relating to sales growth (or decline) and weather.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, and purchased power capacity costs. 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. Cost recovery provisions also include revenues related to the recovery of storm damage restoration costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues" and "Property Damage Reserve" and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Total wholesale revenues were $219.2 million in 2010, an increase of $93.0 million, or 73.7%, compared to 2009 primarily to serve weather-related increases in affiliate demand as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010. Total wholesale revenues were $126.2 million in 2009, a decrease of $77.8 million, or 38.2%, compared to 2008 primarily due to decreased energy sales to affiliates at a lower cost per kilowatt-hour (KWH). Total wholesale revenues were $204.1 million in 2008, an increase of $7.4 million, or 3.7%, compared to 2007 primarily due to higher capacity revenues associated with new and existing territorial wholesale contracts with non-affiliated companies.

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

Revenues from unit power sales increased $7.3 million, or 12.6% in 2010 primarily due to increased capacity revenues as a result of new contracts. Revenues from other power sales increased $7.8 million, or 21.3% in 2010 primarily due to increased KWH sales to serve weather-related increases in non-territorial demand.

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

	2010	2009	2008
		(in thousands)	
Unit power sales –			
Capacity	**$ 33,482**	$ 24,466	$ 22,028
Energy	**31,379**	33,122	33,767
Total	**64,861**	57,588	55,795
Other power sales –			
Capacity and other	**11,158**	11,060	10,890
Energy	**33,153**	25,457	30,380
Total	**44,311**	36,517	41,270
Total non-affiliated	**$ 109,172**	$ 94,105	$ 97,065

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause.

Other operating revenues decreased $7.2 million, or 10.4%, in 2010 primarily due a $10.3 million decrease in revenues from other energy services, partially offset by higher franchise fees of $3.1 million. Other operating revenues increased $7.1 million, or 11.3%, in 2009 primarily due to other energy services and franchise fees, offset by transmission and distribution network services and timber sales. Other operating revenues increased $5.6 million, or 9.9%, in 2008 primarily due to transmission and distribution network services and 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 2010 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change			Weather-Adjusted Percent Change		
	2010	**2010**	2009	2008	**2010**	2009	2008
	(in millions)						
Residential	**5,651**	**7.6%**	(1.8)%	(2.3)%	**(0.2)%**	0.1%	(4.1)%
Commercial	**3,996**	**2.6**	(1.6)	(0.3)	**0.3**	(1.1)	(0.4)
Industrial	**1,686**	**(2.4)**	(21.9)	7.9	**(2.4)**	(21.9)	7.9
Other	**26**	**1.9**	8.1	(5.1)	**1.9**	8.1	(5.1)
Total retail	**11,359**	**4.2**	(5.5)	0.2	**(0.3)%**	(4.6)%	(0.7)%
Wholesale							
Non-affiliates	**1,675**	**(7.6)**	(0.2)	(18.4)			
Affiliates	**2,437**	**180.0**	(53.5)	(35.1)			
Total wholesale	**4,112**	**53.2**	(27.2)	(27.8)			
Total energy sales	**15,471**	**13.9%**	(10.8)%	(8.4)%			

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 increased 7.6% in 2010 compared to 2009 primarily due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010. Weather-adjusted KWH sales to residential customers remained relatively flat as compared to 2009. Residential KWH sales decreased 1.8% in 2009 compared to 2008 primarily due to the recessionary economy. Weather-adjusted KWH sales to residential customers remained relatively flat as compared to 2008. Residential KWH sales decreased 2.3% in 2008 compared to 2007 primarily due to decreased customer usage as a result of a slowing economy, partially offset by more favorable weather.

Commercial KWH sales increased 2.6% in 2010 compared to 2009 primarily due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010. Weather-adjusted KWH sales to commercial customers remained relatively flat as compared to 2009. Commercial KWH sales decreased 1.6% in 2009 compared to 2008 primarily due to the recessionary economy and a decrease in the number of customers. Weather-adjusted KWH sales to commercial customers decreased primarily due to recessionary-driven decreases in per customer usage and in the number of customers as compared to 2008. The change in commercial KWH sales in 2008 compared to 2007 was immaterial.

Industrial KWH sales decreased 2.4% in 2010 compared to 2009 primarily resulting from increased customer co-generation due to the lower cost of natural gas in 2010. Industrial KWH sales decreased 21.9% in 2009 compared to 2008 primarily due to increased customer co-generation due to the lower cost of natural gas in 2009, decreased demand, and a business closure due to the recessionary economy. Industrial KWH sales increased 7.9% in 2008 compared to 2007 primarily due to decreased customer co-generation due to the higher cost of natural gas.

Wholesale KWH sales to non-affiliates decreased 7.6% in 2010, decreased 0.2% in 2009, and decreased 18.4% in 2008 each compared to the prior year. The decrease in 2010 was primarily a result of lower KWHs scheduled by unit power customers. The decrease in 2009 was primarily a result of the recessionary economy. The decrease in 2008 was primarily the result of fluctuations in the fuel cost to produce energy sold to non-affiliated utilities under both long-term and short-term contracts. The degree to which prices for oil and natural gas, which are the primary fuel sources for these customers, differ from the Company's fuel costs will influence these changes in sales. The fluctuations in sales have a minimal effect 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.

Wholesale KWH sales to affiliates increased 180% in 2010, decreased 53.5% in 2009, and decreased 35.1% in 2008, compared to prior years. The increase in 2010 was primarily to serve weather-related increases in affiliate demand due to colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010. The decrease in 2009 was primarily a result of the recessionary economy. The decrease in 2008 was primarily due to the availability of lower cost generation resources at affiliated companies.

Fuel and Purchased Power Expenses

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

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

	2010	2009	2008
Total generation *(millions of KWHs)*	**13,440**	12,895	14,762
Total purchased power *(millions of KWHs)*	**2,858**	1,481	1,187
Sources of generation *(percent)* –			
Coal	**78%**	69%	84%
Gas	**22**	31	16
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**5.10**	4.27	3.58
Gas	**4.68**	4.66	8.02
Average cost of fuel, generated *(cents per net KWH)**	**5.01**	4.39	4.31
Average cost of purchased power *(cents per net KWH)*	**5.82**	6.71	9.21

*Fuel includes fuel purchased by the Company for tolling agreements where power is generated by the provider and is included in purchased power when determining the average cost of purchased power.

Total fuel and purchased power expenses were $839.5 million in 2010, an increase of $174.1 million, or 26.2%, above the prior year costs. The net increase in fuel and purchased power expenses was primarily due to a $116.3 million increase related to total KWHs generated and purchased and a $57.8 million increase in the cost of energy resulting primarily from an increase in the average cost of coal-fired generation and affiliated company power purchases. Total fuel and purchased power expenses were $665.4 million in 2009, a decrease of $79.6 million, or 10.7%, below the prior year costs. The net decrease in fuel and purchased power expenses was primarily due to a $53.3 million decrease related to total KWHs generated and purchased and a $26.3 million decrease in the cost of energy primarily resulting from a decrease in the average cost of natural gas. Total fuel and purchased power expenses were $745.0 million in 2008, an increase of $100.1 million, or 15.5%, above the prior year costs. The net increase in fuel and purchased power expenses was due to a $130.5 million increase in the average cost of fuel and purchased power as well as a $34.9 million increase related to KWHs purchased, offset by a $65.3 million decrease related to KWHs generated.

Fuel expense was $742.3 million in 2010, an increase of $168.9 million, or 29.5%, above the prior year costs. This increase was primarily the result of a 19.4% increase in the average cost of coal and a 4.2% increase in KWHs generated as a result of higher demand. Fuel expense was $573.4 million in 2009, a decrease of $62.2 million, or 9.8%, below the prior year costs. This decrease was primarily the result of a 41.9% decrease in the average cost of natural gas and a 12.6% decrease in KWHs generated as a result of lower demand, partially offset by an increase of 19.3% in the average cost of coal per KWH generated. Fuel expense was $635.6 million in 2008, an increase of $62.2 million, or 10.9%, above the prior year costs. This increase was the result of a 25.3% increase in the average cost of fuel, offset by an 11.4% decrease in KWHs generated.

Purchased power expense was $97.2 million in 2010, an increase of $5.2 million, or 5.7%, above the prior year costs. This increase was the result of a 92.9% increase in the volume of KWHs purchased, offset by a 13.3% decrease in the average cost per KWH purchased. Purchased power expense was $92.0 million in 2009, a decrease of $17.4 million, or 15.9%, below the prior year costs. This decrease was primarily the result of a 27.1% decrease in the average cost per KWH purchased, offset by a 24.8% increase in the volume of KWHs purchased. Purchased power expense was $109.4 million in 2008, an increase of $37.9 million, or 53.0%, above the prior year costs. This increase was the result of a 48.8% increase in total KWHs purchased and a 2.8% increase in the average cost per net KWH.

From an overall global market perspective, coal prices increased substantially in 2010 from the levels experienced in 2009, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2010, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. These lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2009 and 2010.

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

Other Operations and Maintenance Expenses

In 2010, other operations and maintenance expenses increased $20.3 million, or 7.8%, compared to the prior year primarily due to a $20.2 million increase in scheduled and unscheduled maintenance at generation facilities. In 2009, other operations and maintenance expenses decreased $17.2 million, or 6.2%, compared to the prior year primarily due to a $14.4 million decrease in administrative and general expense, most of which was related to decreased storm recovery costs, and a $6.7 million decrease in power generation, most of which was related to scheduled and unscheduled maintenance and cost containment activities in an effort to offset the effects of the recessionary economy. This decrease was partially offset by a $4.8 million increase in other energy services. In 2008, other operations and maintenance expenses increased $7.1 million, or 2.6%, compared to the prior year primarily due to an $8.2 million increase in scheduled and unscheduled maintenance at generation facilities.

Depreciation and Amortization

Depreciation and amortization increased $28.1 million, or 30.1%, in 2010 compared to the prior year primarily due to the addition of an environmental control project at Plant Crist being placed into service in December 2009 and other net additions to generation and distribution facilities. Approximately $19.0 million of the increase was related to the environmental control project at Plant Crist and was recovered through the environmental clause; therefore, it had no material impact on net income. Depreciation and amortization increased $8.6 million, or 10.1%, in 2009 compared to the prior year primarily due to additions of environmental control projects at Plant Crist and Plant Scherer and other net additions to generation and distribution facilities. Depreciation and amortization decreased $0.8 million, or 0.9%, in 2008 compared to the prior year primarily as a result of a $3.8 million gain on the sale of a building. The decrease was partially offset by an increase of $3.0 million in depreciation due to net additions to generation and distribution facilities.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7.3 million, or 7.7%, in 2010 compared to the prior year primarily due to a $5.5 million increase in gross receipt and franchise fees and a $1.0 million increase in payroll taxes. Taxes other than income taxes increased $7.3 million, or 8.3%, in 2009 compared to the prior year primarily due to a $5.6 million increase in gross receipts and franchise taxes and a $1.6 million increase in property taxes. Taxes other than income taxes increased $4.2 million, or 5.1%, in 2008 compared to the prior year primarily due to a $1.9 million decrease in 2007 related to the resolution of a dispute regarding property taxes in Monroe County, Georgia and a $1.9 million increase in franchise and gross receipt taxes. Gross receipts and franchise taxes have no impact on net income.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $16.6 million, or 69.7%, in 2010 compared to the prior year primarily due to an environmental control project at Plant Crist being placed into service in December 2009. AFUDC equity increased $13.8 million, or 138.8%, in 2009 compared to the prior year primarily due to construction of environmental control projects at Plant Crist and Plant Scherer. AFUDC equity increased $7.6 million, or 319.9%, in 2008 compared to the prior year primarily due to construction of environmental control projects at Plant Crist and Plant Scherer. See Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $13.5 million, or 35.3%, in 2010 compared to the prior year as the result of a reduction in capitalized interest for an environmental control project at Plant Crist being placed into service in December 2009. The increased interest was also primarily due to an increase in long-term debt levels resulting from the issuance of additional senior notes in 2010 to fund general corporate purposes, including the Company's continuous construction program. Interest expense, net of amounts capitalized decreased $4.7 million, or 11.0%, in 2009 compared to the prior year as the result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects at Plant Crist and Plant Scherer. Interest expense, net of amounts capitalized decreased $1.6 million, or 3.5%, in 2008 compared to the prior year as the result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects and the redemption of $41.2 million of long-term debt payable to an affiliated trust in 2007. These decreases were offset by the issuance of a $110 million term loan agreement in 2008.

Income Taxes

Income taxes increased $18.5 million, or 34.9%, in 2010, compared to the prior year primarily as a result of higher earnings before income taxes and a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable. Income taxes decreased $1.1 million, or 2.0%, in 2009 compared to the prior year primarily due to the tax benefit associated with an increase in AFUDC equity, which is non-taxable, partially offset by higher earnings before taxes. Income taxes increased $7.0 million, or 14.9%, in 2008, compared to the prior year primarily due to higher earnings before income taxes and a decrease in the federal production activities deduction, partially offset by the tax benefit associated with an increase in AFUDC equity, which is non-taxable. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for electricity relating to 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 for additional information about regulatory matters.

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

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including 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. 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. After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power, including one facility co-owned by the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. In July 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power with respect to its other affected units regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. On September 2, 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims for summary disposition or trial. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

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

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005 and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. In November 2009, the plaintiffs filed an appeal with the U.S. Court of Appeals for the Ninth Circuit challenging the district court's order dismissing the case. On January 24, 2011, the defendants filed a motion with the U.S. Court of Appeals for the Ninth Circuit to defer scheduling the case pending the decision of the U.S. Supreme Court in the New York case discussed above. The ultimate outcome of this matter cannot be determined at this time.

Other Litigation

Common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas emissions have become more frequent, and, as illustrated by the New York and Kivalina cases, courts have been debating whether private parties and states have standing to bring such claims. In another common law nuisance case, the U.S. District Court for the Southern District of Mississippi dismissed private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. The court ruled that the parties lacked standing to bring the claims and the claims were barred by the political question doctrine. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the district court and held that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and none of the claims were barred by the political question doctrine. On May 28, 2010, however, the U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal of the case based on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the U.S. Supreme Court denied the plaintiffs' petition to reinstate the appeal. This case is now concluded.

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 2010, the Company had invested approximately $1.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $136 million, $343 million, and $296 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $176 million, $228 million, and $214 million for 2011, 2012, and 2013, respectively. These environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations of up to $17 million in 2011, up to $56 million in 2012, and up to $107 million in 2013. The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances, and the Company's fuel mix.

The Florida Legislature has adopted legislation that allows 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 legislation is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, including coal ash, water quality, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. 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. Through 2010, the Company had spent approximately $953 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. As a result, emissions control projects have been completed recently or are underway. 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. No area within the Company's service area is currently designated as nonattainment under the current standard. In March 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard, and on January 6, 2010, the EPA proposed further reductions in the level of the standard. Under the EPA's current schedule, a final revision to the eight-hour ozone standard is expected in July 2011, with state implementation plans for any resulting nonattainment areas due in mid-2014. The revised eight-hour ozone standard is expected to result in designation of new nonattainment areas within the Company's service territory, and could result in additional required reductions in NO_x emissions.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the State of Georgia, which includes the Company's co-owned facility. State implementation plans demonstrating attainment with the annual standard for all areas have been submitted to the EPA. The EPA is expected to propose new annual and 24-hour fine particulate matter standards during the summer of 2011.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective on August 23, 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. Implementation of the revised SO_2 standard could result in additional required reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective on April 12, 2010. Although none of the areas within the Company's service territory are expected to be designated as nonattainment for the NO_2 standard, based on current ambient air quality monitoring data, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

Twenty-eight eastern states, including the states of Florida, Georgia, and Mississippi, are subject to the requirements of the Clean Air Interstate Rule (CAIR). The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. In July 2008 and December 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating certain aspects of CAIR, but left CAIR compliance requirements in place while the EPA develops a revised rule. The states of Florida, Georgia, and Mississippi have completed plans to implement CAIR, and emissions reductions are being accomplished by the installation and operation of emissions controls at the Company's coal-fired facilities and/or by the purchase of emissions allowances.

On August 2, 2010, the EPA published a proposed rule, referred to as the Transport Rule, to replace CAIR. This proposed rule would require 31 eastern states and the District of Columbia (D.C.) to reduce power plant emissions of SO_2 and NO_x that contribute to downwind states' nonattainment of federal ozone and/or fine particulate matter ambient air quality standards. To address fine particulate matter standards, the proposed Transport Rule would require D.C. and 27 eastern states, including Florida and Georgia, to reduce annual emissions of SO_2 and NO_x from power plants. To address ozone standards, the proposed Transport Rule would also require D.C. and 25 states, including Florida, Georgia, and Mississippi, to achieve additional reductions in NO_x emissions from power plants during the ozone season. The proposed Transport Rule contains a "preferred option" that would allow limited interstate trading of emissions allowances; however, the EPA also requested comment on two alternative approaches that would not allow interstate trading of emissions allowances. The EPA stated that it also intends to develop a second phase of the Transport Rule in 2011 to address the more stringent ozone air quality standards after they are finalized. The EPA expects to finalize the Transport Rule in June 2011 and require compliance beginning in 2012.

The Clean Air Visibility Rule was finalized in July 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. For power plants, the Clean Air Visibility Rule allows states to determine that CAIR satisfies BART requirements for SO_2 and NO_x, and no additional controls beyond CAIR are anticipated to be necessary at the Company's facilities. States have completed or are currently completing implementation plans for BART compliance and other measures required to achieve the first phase of reasonable progress.

The EPA is currently developing a Maximum Achievable Control Technology (MACT) rule for coal- and oil-fired electric generating units which will establish emission limitations for numerous hazardous air pollutants, including mercury. As part of a proceeding in the U.S. District Court for the District of Columbia, the EPA has entered into a consent decree that requires the EPA to issue a proposed MACT rule by March 16, 2011 and a final rule by November 16, 2011.

The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the proposed Transport Rule, the Clean Air Visibility Rule, and the proposed MACT rule for electric generating units on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of any pending and future legal challenges, and the development and implementation of rules at the state level. However, these additional regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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

Water Quality

In July 2004, the EPA published final regulations under the Clean Water Act to reduce impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The use of cost-benefit analysis in the rule was ultimately appealed to the U.S. Supreme Court. In April 2009, the U.S. Supreme Court held that the EPA could consider costs in arriving at its standards and in providing variances from those standards for existing intake structures. The EPA is expected to propose revisions to the regulations in March 2011 and issue final regulations in mid-2012. While the U.S. Supreme Court's decision may ultimately result in greater flexibility for demonstrating compliance with the standards, the full scope of the regulations will depend on the specific provisions of the EPA's final rule and on the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time. However, if the final rules require the installation of cooling towers at certain existing facilities of the Company, the Company may be subject to significant additional compliance costs and capital expenditures 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.

In December 2009, the EPA announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted, and the EPA has announced its intention to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain Company facilities. The impact of revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

In addition, the State of Florida is finalizing 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.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. 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.

Coal Combustion Byproducts

The Company currently operates three electric generating plants with on-site coal combustion byproduct storage facilities (some with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company utilizes a portion of its coal combustion byproducts for beneficial reuse (approximately 20% in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the States of Florida, Georgia and Mississippi, each have their own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. On June 21, 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options.

On November 19, 2010, Southern Company filed publicly available comments with the EPA regarding the rulemaking proposal. These comments included a preliminary cost analysis under various alternatives in the rulemaking proposal. The Company regards these estimates as pre-screening figures that should be distinguished from the more formalized cost estimates the Company provides for projects that are more definite as to the elements and timing of execution. Although its analysis was preliminary, Southern Company concluded that potential compliance costs under the proposed rules would be substantially higher than the estimates reflected in the EPA's rulemaking proposal.

The ultimate financial and operational impact of any new regulations relating to coal combustion byproducts cannot be determined at this time and will be dependent upon numerous factors. These factors include: whether coal combustion byproducts will be regulated as hazardous waste or non-hazardous waste; whether the EPA will require early closure of existing wet storage facilities; whether beneficial reuse will be limited or eliminated through a hazardous waste designation; whether the construction of lined landfills is required; whether hazardous waste landfill permitting will be required for on-site storage; whether additional waste water treatment will be required; the extent of any additional groundwater monitoring requirements; whether any equipment modifications will be required; the extent of any changes to site safety practices under a hazardous waste designation; and the time period over which compliance will be required. There can be no assurance as to the timing of adoption or the ultimate form of any such rules.

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.

Global Climate Issues

Although the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, with the goal of mandating renewable energy standards and reductions in greenhouse gas emissions, neither this legislation nor similar measures passed the U.S. Senate before the end of the 2010 session. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards, and/or energy efficiency standards are expected to continue to be considered in Congress.

The financial and operational impacts of climate or energy legislation, if enacted, will depend on a variety of factors. These factors include the specific greenhouse gas emissions limits or renewable energy requirements, the timing of implementation of these limits or requirements, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through regulated rates.

While climate legislation has yet to be adopted, the EPA is moving forward with regulation of greenhouse gases under the Clean Air Act. In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. In December 2009, the EPA published a final determination, which became effective on January 14, 2010, that certain greenhouse gas emissions from new motor vehicles endanger public health and welfare due to climate change. On April 1, 2010, the EPA issued a final rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. The EPA has taken the position that when this rule became effective on January 2, 2011, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit and the installation of the best available control technology for carbon dioxide and other greenhouse gases. On May 13, 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. This rule establishes two phases for applying PSD and Title V requirements to greenhouse gas emissions sources. The first phase, which began on January 2, 2011, applies to sources and projects that would already be covered under PSD or Title V, whereas the second phase will begin on July 1, 2011 and applies to sources and projects that would not otherwise trigger those programs but for their greenhouse gas emissions. In addition to these rules, the EPA has entered into a proposed settlement agreement to issue standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units and greenhouse gas emissions guidelines for existing sources. Under the proposed settlement agreement, the EPA commits to issue the proposed standards by July 2011 and the final standards by May 2012.

All of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit; however, the court declined motions to stay the rules pending resolution of those challenges. As a result, the rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate outcome of these rules cannot be determined at this time and will depend on the content of the final rules and the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. The December 2009 negotiations resulted in a nonbinding agreement that included a pledge from both developed and developing countries to reduce their greenhouse gas emissions. The most recent round of negotiations took place in December 2010. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency on the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" 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.

In 2009, the total carbon dioxide emissions from the fossil fuel-fired electric generating units owned by the Company were approximately 11 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 13 million metric tons. The level of carbon dioxide emissions from year to year will be dependent on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

PSC Matters

General

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.

In November 2010, the Florida PSC approved the Company's annual cost recovery clause requests for its fuel, purchased power capacity, energy conservation, and environmental compliance cost recovery factors for 2011. The net effect of the approved changes to the Company's cost recovery factors for 2011 is a 2.8% rate decrease for residential customers using 1,000 KWHs per month. The billing factors for 2011 are intended to allow the Company to recover projected 2011 costs as well as refund or collect the 2010 over or under recovered amounts in 2011. 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, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, for additional information.

Fuel Cost Recovery

The Company petitions for fuel cost recovery rates to be approved by the Florida PSC on an annual basis. The fuel cost recovery rates include the costs of fuel and purchased energy. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. If, at any time during the year, the projected 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. The change in the fuel cost under-recovered balance during 2010 was primarily due to higher than expected fuel costs and purchased power energy expenses. At December 31, 2010 and 2009, the under recovered fuel balance was approximately \$17.4 million and \$2.4 million, respectively, which is included in under recovered regulatory clause revenues, current in the balance sheets.

Purchased Power Capacity Recovery

The Florida PSC allows the Company to recover its costs for capacity purchased from other power producers under power purchase agreements (PPAs) through a separate cost recovery component or factor in the Company's retail energy rates. Like the other specific cost recovery factors included in the Company's retail energy rates, the rates for purchased capacity are set annually. When the Company enters into a new PPA, it is reviewed and approved by the Florida PSC for cost recovery purposes. As of December 31, 2010 and 2009, the Company had an over recovered purchased power capacity balance of approximately \$4.4 million and \$1.5 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

In August 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that are scheduled to be implemented in the 2007 through 2011 timeframe. On April 1, 2010, the Company filed an update to the plan, which was approved by the Florida PSC on November 15, 2010. The Florida PSC acknowledged that the costs associated with the Company's CAIR 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, 2010 and 2009, the over recovered environmental balance was approximately $10.4 million and $11.7 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein, Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery," and Note 7 to the financial statements under "Construction Program" for additional information.

On July 22, 2010, Mississippi Power Company (Mississippi Power) filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership, respectively. The estimated total cost of the project is approximately $625 million. The project is scheduled for completion in the fourth quarter 2014. The Company's portion of the cost, if approved by the Florida PSC, is expected to be recovered through the environmental compliance recovery clause. Hearings on the certificate request were held with the Mississippi PSC on January 25, 2011 with a final order expected by February 28, 2011. The ultimate outcome of this matter cannot now be determined.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy, formally accepting a $165 million grant under the American Recovery and Reinvestment Act of 2009. This funding will be used for transmission and distribution automation and modernization projects that must be completed by April 28, 2013. The Company will receive, and will match, $15.5 million under the agreement. The ultimate outcome of this matter cannot be determined at this time.

Healthcare Reform

On March 23, 2010, the Patient Protection and Affordable Care Act (PPACA) was signed into law and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010 (together with PPACA, the Acts), which makes various amendments to certain aspects of the PPACA, was signed into law. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (MPDIMA). Since the 2006 tax year, the Company has been receiving the federal subsidy related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the MPDIMA, the federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Under the Acts, beginning in 2013, an employer's income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Under generally accepted accounting principles (GAAP), any impact from a change in tax law must be recognized in the period enacted regardless of the effective date; however, as a result of state regulatory treatment, this change had no material impact on the Company's financial statements. Southern Company continues to assess the extent to which the legislation and associated regulations may affect its future healthcare and related employee benefit plan costs. Any future impact on the Company's financial statements cannot be determined at this time. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Income Tax Matters

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $8 million for the Company. Although IRS approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Bonus Depreciation

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which could have a significant impact on the future cash flows of the Company. The application of the bonus depreciation provisions in these acts in 2010 provided approximately $36 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $40 million and $50 million.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code of 1986, as amended. The deduction is equal to a stated percentage of qualified production activities net income. The percentage was phased in over the years 2005 through 2010. For 2008 and 2009, a 6% reduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation and pension contributions there was no domestic production deduction available to the Company for 2010 and none is projected to be available for 2011. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

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 opacity and air and water quality standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with 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 and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and 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 potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with 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.

These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, coal combustion byproducts, including coal ash, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, state revenue departments, the FERC, or the EPA.

Unbilled Revenues

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

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, health care 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 would result in a $1.1 million or less change in total benefit expense and a $13 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2010. 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" and "Financing Activities" herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2010. In December 2010, the Company contributed $28 million to the qualified pension plan.

Net cash provided from operating activities totaled $267.8 million, $194.2 million, and $147.9 million for 2010, 2009, and 2008, respectively. The $73.5 million increase in net cash provided from operating activities in 2010 was primarily due to a $99.2 million increase from deferred income taxes related to bonus depreciation and a $90.9 million decrease in fuel inventory, partially offset by a $109.4 million increase in accounts receivable related to fuel cost and a $25.7 million decrease related to the qualified pension plan. The $46.3 million increase in net cash provided from operating activities in 2009 was primarily due to a $134.5 million reduction in accounts receivable related to fuel cost, partially offset by a $40.5 million decrease in deferred income taxes and a $38.4 million increase in fuel inventory. The $69.1 million decrease in net cash provided from operating activities in 2008 was due primarily to a $61.0 million increase in cash used for the under recovered regulatory clause related to fuel.

Net cash used for investing activities totaled $308.4 million, $468.4 million, and $348.7 million for 2010, 2009, and 2008, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $285.4 million, $450.4 million, and $390.7 million for 2010, 2009, and 2008, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash provided from financing activities totaled $48.4 million, $279.4 million, and $198.8 million for 2010, 2009, and 2008, respectively. The $231.0 million decrease in net cash provided from financing activities in 2010 was due primarily to $194.4 million higher issuances of pollution control revenue bonds and common stock in 2009 and a net $54.3 million decrease in senior notes outstanding. The $80.6 million increase in net cash provided from financing activities in 2009 was due primarily to $258.4 million in higher debt issuances and cash raised from a common stock sale, partially offset by a $157.0 million decrease in notes payable. The $178.6 million increase in net cash provided from financing activities in 2008 was due primarily to the issuance of $110 million in long-term debt and $50 million in short-term debt, and a $49.1 million change in commercial paper cash flows in 2008. The increase was partially offset by the issuance of $85 million in senior notes in 2007.

Significant balance sheet changes in 2010 include increases in customer accounts receivable of $10.1 million; under recovered regulatory clause revenues of $15.4 million; other regulatory assets, deferred of $28.9 million, primarily due to an increase in PPA deferred capacity expense, and accumulated deferred income taxes of $85.5 million. Total property, plant, and equipment increased by $194.9 million primarily due to environmental control projects. Securities due within one year decreased by $30.0 million primarily due to senior notes maturing in the first quarter 2010. Employee benefit obligations decreased by $32.6 million primarily due to funding of the Company's qualified pension plan.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.1% in 2010, 43.4% in 2009, and 42.9% in 2008. See Note 6 to the financial statements for additional information.

Sources of Capital

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

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

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

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

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At December 31, 2010, the Company had approximately $16.4 million of cash and cash equivalents, along with $240 million of unused committed lines of credit with banks to meet its short-term cash needs. These bank credit arrangements will expire in 2011 and $210 million contain provisions allowing one-year term loans executable at expiration. In February 2011, the Company renewed a $30 million credit facility. The Company plans to renew the other lines of credit during 2011 prior to their 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, 2010, the Company had $69 million outstanding of pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support. At December 31, 2010, the Company had $1.2 million in notes payable outstanding related to other energy services contracts. At December 31, 2010, the Company had approximately $92.0 million of commercial paper borrowings outstanding with a weighted average interest rate of 0.3% per annum. During 2010, the Company had an average of $44 million of commercial paper outstanding at a weighted average interest rate of 0.3% per annum and the maximum amount outstanding was $108 million. At December 31, 2009, the Company had $88.9 million of commercial paper borrowings outstanding with a weighted average interest rate of 1.0% per annum. During 2009, the Company had an average of $51.7 million of commercial paper outstanding at a weighted average interest rate of 1.0% per annum and the maximum amount outstanding was $152.1 million. 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 2010, the Company issued to Southern Company 500,000 shares of common stock, without par value, and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes.

In April 2010, the Company issued $175 million aggregate principal amount of Series 2010A 4.75% Senior Notes due April 15, 2020. The net proceeds were used to repay at maturity $140 million aggregate principal amount of Series 2009A Floating Rate Senior Notes due June 28, 2010, to repay a portion of its outstanding short-term debt, and for general corporate purposes, including the Company's continuous construction program. The Company settled $100 million of interest rate hedges related to the Series 2010A Senior Note issuance at a gain of approximately $1.5 million. The gain will be amortized to interest expense over 10 years.

In June 2010, the Company incurred obligations in connection with the issuance of $21 million aggregate principal amount of the Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Gulf Power Plant Scherer Project), First Series 2010. The proceeds were used to fund pollution control and environmental improvement facilities at Plant Scherer.

In September 2010, the Company issued $125 million aggregate principal amount of its Series 2010B 5.10% Senior Notes due October 1, 2040. The net proceeds were used to repay a portion of its outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program, and for the redemption of all of the $40 million aggregate principal amount of the Company's Series I 5.75% Senior Notes due September 15, 2033 and $35 million aggregate principal amount of the Company's Series J 5.875% Senior Notes due April 1, 2044.

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

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. At December 31, 2010, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $125 million. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $548 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

On August 12, 2010, Moody's Investors Service (Moody's) downgraded the issuer and long-term debt ratings of the Company (senior unsecured to A3 from A2); Moody's also announced that it had downgraded the short-term ratings of a financing subsidiary of Southern Company that issues commercial paper for the benefit of several Southern Company subsidiaries (including the Company) to P-2 from P-1. In addition, Moody's announced that it had downgraded the variable rate demand obligation ratings of the Company to VMIG-2 from VMIG-1 and the preferred and preference stock ratings of the Company (to Baa2 from Baa1). Moody's announced that the ratings outlook for the Company is stable.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $179 million of outstanding variable rate long-term debt at December 31, 2010 was 0.62%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $1.8 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for 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, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2010 Changes	2009 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (13,687)**	$ (31,161)
Contracts realized or settled	**17,613**	41,683
Current period changes[a]	**(15,154)**	(24,209)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (11,228)**	$ (13,687)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2010 was an increase of $2.5 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2010, the Company had a net hedge volume of 19.6 million mmBtu with a weighted average contract cost approximately $0.67 per mmBtu above market prices and 10.7 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.29 per mmBtu above market prices. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2010 and 2009, 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 actively quoted, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurement. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2010 were as follows:

	December 31, 2010 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in thousands)		
Level 1	**$ -**	**$ -**	**$ -**	**$ -**
Level 2	**(11,228)**	**(7,609)**	**(3,619)**	**-**
Level 3	**-**	**-**	**-**	**-**
Fair value of contracts outstanding at end of period	**$ (11,228)**	**$ (7,609)**	**$ (3,619)**	**$ -**

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to include a base level investment of $381.5 million, $395.5 million, and $384.1 million for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $175.9 million, $227.8 million, and $214.0 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations of up to $17.1 million for 2011, up to $55.6 million for 2012, and up to $107.3 million for 2013. 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; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing(d)	Total
			(in thousands)			
Long-term debt(a) –						
Principal	$ 110,000	$ 60,000	$ 75,000	$ 985,926	$ -	$ 1,230,926
Interest	51,902	102,242	93,347	552,551	-	800,042
Energy-related derivative obligations(b)	9,415	4,193	-	-	-	13,608
Preference stock dividends(c)	6,203	12,405	12,405	-	-	31,013
Operating leases	20,629	32,822	15,070	1,045	-	69,566
Unrecognized tax benefits and interest(d)	-	-	-	-	4,080	4,080
Purchase commitments(e) –						
Capital(f)	381,451	779,667	-	-	-	1,161,118
Limestone(g)	6,371	13,225	13,894	29,934	-	63,424
Coal	312,244	119,773	-	-	-	432,017
Natural gas(h)	104,977	161,412	165,395	209,308	-	641,092
Purchased power(i)	40,911	86,776	159,655	685,750	-	973,092
Long-term service agreements(j)	6,470	13,429	14,108	16,499	-	50,506
Pension and other postretirement benefit plans(k)	-	-	-	-	-	-
Total	$ 1,050,573	$ 1,385,944	$ 548,874	$ 2,481,013	$ 4,080	$ 5,470,484

(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, 2011, as reflected in the statements of capitalization.

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

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

(d) The timing related to the realization of $4.1 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2010, 2009, and 2008 were $280 million, $260 million, and $277 million, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding the Company's estimates of potential incremental investments to comply with anticipated new environmental regulations of up to $17.1 million for 2011, up to $55.6 million for 2012, and up to $107.3 million for 2013. At December 31, 2010, significant purchase commitments were outstanding in connection with the construction program.

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

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2010.

(i) 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.

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

(k) The Company forecasts contributions to the qualified pension and other postretirement benefit plans over a three-year period. The Company does not expect to be required to make any contributions to the qualified pension plan during the next three years. 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 2010 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, fuel cost recovery and other rate actions, environmental regulations and expenditures, future earnings, access to sources of capital, economic recovery, projections for the qualified pension plan and postretirement benefit trust contributions, financing activities, start and completion of construction projects, impacts of adoption of new accounting rules, impact of the American Recovery and Reinvestment Act of 2009, impact of recent healthcare legislation, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and the EPA civil actions against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population, and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as 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, 2010, 2009, and 2008

Gulf Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Revenues:			
Retail revenues	**$1,308,726**	$1,106,568	$1,120,766
Wholesale revenues, non-affiliates	**109,172**	94,105	97,065
Wholesale revenues, affiliates	**110,051**	32,095	106,989
Other revenues	**62,260**	69,461	62,383
Total operating revenues	**1,590,209**	1,302,229	1,387,203
Operating Expenses:			
Fuel	**742,322**	573,407	635,634
Purchased power, non-affiliates	**41,278**	23,706	29,590
Purchased power, affiliates	**55,948**	68,276	79,750
Other operations and maintenance	**280,585**	260,274	277,478
Depreciation and amortization	**121,498**	93,398	84,815
Taxes other than income taxes	**101,778**	94,506	87,247
Total operating expenses	**1,343,409**	1,113,567	1,194,514
Operating Income	**246,800**	188,662	192,689
Other Income and (Expense):			
Allowance for equity funds used during construction	**7,213**	23,809	9,969
Interest income	**123**	423	3,155
Interest expense, net of amounts capitalized	**(51,897)**	(38,358)	(43,098)
Other income (expense), net	**(3,011)**	(4,075)	(4,064)
Total other income and (expense)	**(47,572)**	(18,201)	(34,038)
Earnings Before Income Taxes	**199,228**	170,461	158,651
Income taxes	**71,514**	53,025	54,103
Net Income	**127,714**	117,436	104,548
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$121,511**	$111,233	$ 98,345

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009, and 2008
Gulf Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Operating Activities:			
Net income	**$127,714**	$ 117,436	$ 104,548
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**127,897**	99,564	93,607
Deferred income taxes	**82,681**	(16,545)	23,949
Allowance for equity funds used during construction	**(7,213)**	(23,809)	(9,969)
Pension, postretirement, and other employee benefits	**(23,964)**	1,769	1,585
Stock based compensation expense	**1,101**	933	765
Hedge settlements	**1,530**	-	(5,220)
Other, net	**(4,126)**	(5,173)	(4,934)
Changes in certain current assets and liabilities --			
-Receivables	**(36,687)**	83,245	(49,886)
-Prepayments	**(10,796)**	(192)	(310)
-Fossil fuel stock	**15,766**	(75,145)	(36,765)
-Materials and supplies	**(6,251)**	(1,642)	8,927
-Prepaid income taxes	**(29,630)**	(6,355)	(416)
-Property damage cost recovery	**-**	10,746	26,143
-Other current assets	**55**	(12)	3
-Accounts payable	**15,683**	7,890	(4,561)
-Accrued taxes	**1,427**	(2,404)	(6,511)
-Accrued compensation	**5,122**	(6,330)	570
-Other current liabilities	**7,471**	10,255	6,417
Net cash provided from operating activities	**267,780**	194,231	147,942
Investing Activities:			
Property additions	**(285,793)**	(421,309)	(377,790)
Investment in restricted cash from pollution control revenue bonds	**-**	(49,188)	-
Distribution of restricted cash from pollution control revenue bonds	**6,347**	42,841	-
Cost of removal net of salvage	**(1,145)**	(9,751)	(8,713)
Construction payables	**(21,581)**	(23,603)	37,244
Payments pursuant to long-term service agreements	**(6,011)**	(7,421)	(5,468)
Other investing activities	**(262)**	(5)	6,044
Net cash used for investing activities	**(308,445)**	(468,436)	(348,683)
Financing Activities:			
Increase (decrease) in notes payable, net	**4,451**	(49,599)	107,438
Proceeds --			
Common stock issued to parent	**50,000**	135,000	-
Capital contributions from parent company	**2,242**	22,032	75,324
Pollution control revenue bonds	**21,000**	130,400	37,000
Senior notes	**300,000**	140,000	-
Other long-term debt issuances	**-**	-	110,000
Redemptions --			
Pollution control revenue bonds	**-**	-	(37,000)
Senior notes	**(215,515)**	(1,214)	(1,300)
Payment of preference stock dividends	**(6,203)**	(6,203)	(6,057)
Payment of common stock dividends	**(104,300)**	(89,300)	(81,700)
Other financing activities	**(3,253)**	(1,677)	(4,869)
Net cash provided from financing activities	**48,422**	279,439	198,836
Net Change in Cash and Cash Equivalents	**7,757**	5,234	(1,905)
Cash and Cash Equivalents at Beginning of Year	**8,677**	3,443	5,348
Cash and Cash Equivalents at End of Year	**$ 16,434**	$ 8,677	$ 3,443
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $2,875, $9,489 and $3,973 capitalized, respectively)	**$42,521**	$40,336	$39,956
Income taxes (net of refunds)	**17,224**	73,889	40,176
Noncash decrease in notes payable related to energy services	**-**	(8,309)	-
Noncash transactions - accrued property additions at year-end	**14,475**	42,050	61,006

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

BALANCE SHEETS
At December 31, 2010 and 2009
Gulf Power Company 2010 Annual Report

Assets	2010	2009
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 16,434**	$ 8,677
Restricted cash and cash equivalents	**-**	6,347
Receivables --		
Customer accounts receivable	**74,377**	64,257
Unbilled revenues	**64,697**	60,414
Under recovered regulatory clause revenues	**19,690**	4,285
Other accounts and notes receivable	**9,867**	4,107
Affiliated companies	**7,859**	7,503
Accumulated provision for uncollectible accounts	**(2,014)**	(1,913)
Fossil fuel stock, at average cost	**167,155**	183,619
Materials and supplies, at average cost	**44,729**	38,478
Other regulatory assets, current	**20,278**	19,172
Prepaid expenses	**58,412**	44,760
Other current assets	**3,585**	3,634
Total current assets	**485,069**	443,340
Property, Plant, and Equipment:		
In service	**3,634,255**	3,430,503
Less accumulated provision for depreciation	**1,069,006**	1,009,807
Plant in service, net of depreciation	**2,565,249**	2,420,696
Construction work in progress	**209,808**	159,499
Total property, plant, and equipment	**2,775,057**	2,580,195
Other Property and Investments	**16,352**	15,923
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**46,357**	39,018
Prepaid pension costs	**7,291**	-
Other regulatory assets, deferred	**219,877**	190,971
Other deferred charges and assets	**34,936**	24,160
Total deferred charges and other assets	**308,461**	254,149
Total Assets	**$3,584,939**	$3,293,607

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

BALANCE SHEETS

At December 31, 2010 and 2009

Gulf Power Company 2010 Annual Report

Liabilities and Stockholder's Equity	**2010**	2009
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$110,000**	$140,000
Notes payable	**93,183**	90,331
Accounts payable --		
Affiliated	**46,342**	47,421
Other	**68,840**	80,184
Customer deposits	**35,600**	32,361
Accrued taxes --		
Accrued income taxes	**3,835**	1,955
Other accrued taxes	**7,944**	7,297
Accrued interest	**13,393**	10,222
Accrued compensation	**14,459**	9,337
Other regulatory liabilities, current	**27,060**	22,416
Liabilities from risk management activities	**9,415**	9,442
Other current liabilities	**19,766**	20,092
Total current liabilities	**449,837**	471,058
Long-Term Debt (See accompanying statements)	**1,114,398**	978,914
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**382,876**	297,405
Accumulated deferred investment tax credits	**8,109**	9,652
Employee benefit obligations	**76,654**	109,271
Other cost of removal obligations	**204,408**	191,248
Other regulatory liabilities, deferred	**42,915**	41,399
Other deferred credits and liabilities	**132,708**	92,370
Total deferred credits and other liabilities	**847,670**	741,345
Total Liabilities	**2,411,905**	2,191,317
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,075,036**	1,004,292
Total Liabilities and Stockholder's Equity	**$3,584,939**	$3,293,607
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2010 and 2009

Gulf Power Company 2010 Annual Report

	2010	2009	2010	2009
	(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		
4.75% to 5.90% due 2016-2044	**676,971**	452,486		
Variable rates (0.35% at 1/1/10) due 2010	**-**	140,000		
Variable rates (0.71% at 1/1/11) due 2011	**110,000**	110,000		
Total long-term notes payable	**921,971**	837,486		
Other long-term debt --				
Pollution control revenue bonds --				
1.50% to 6.00% due 2022-2049	**239,625**	218,625		
Variable rates (0.39% to 0.47% at 1/1/11) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	287,955		
Unamortized debt discount	**(6,528)**	(6,527)		
Total long-term debt (annual interest requirement -- $51.9 million)	**1,224,398**	1,118,914		
Less amount due within one year	**110,000**	140,000		
Long-term debt excluding amount due within one year	**1,114,398**	978,914	**48.7%**	47.0%
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	**4.3**	4.7
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 20,000,000 shares				
Outstanding - 2010: 3,642,717 shares				
Outstanding - 2009: 3,142,717 shares	**303,060**	253,060		
Paid-in capital	**538,375**	534,577		
Retained earnings	**236,328**	219,117		
Accumulated other comprehensive income (loss)	**(2,727)**	(2,462)		
Total common stockholder's equity	**1,075,036**	1,004,292	**47.0**	48.3
Total Capitalization	**$2,287,432**	$2,081,204	**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, 2010, 2009, and 2008
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2007	1,793	$118,060	$435,008	$181,986	$(3,799)	$731,255
Net income after dividends on preference stock	-	-	-	98,345	-	98,345
Capital contributions from parent company	-	-	76,539	-	-	76,539
Other comprehensive income (loss)	-	-	-	-	(1,133)	(1,133)
Cash dividends on common stock	-	-	-	(81,700)	-	(81,700)
Change in benefit plan measurement date	-	-	-	(1,214)	-	(1,214)
Balance at December 31, 2008	1,793	118,060	511,547	197,417	(4,932)	822,092
Net income after dividends on preference stock	-	-	-	111,233	-	111,233
Issuance of common stock	1,350	135,000	-	-	-	135,000
Capital contributions from parent company	-	-	23,030	-	-	23,030
Other comprehensive income (loss)	-	-	-	-	2,470	2,470
Cash dividends on common stock	-	-	-	(89,300)	-	(89,300)
Change in benefit plan measurement date	-	-	-	(233)	-	(233)
Balance at December 31, 2009	**3,143**	**253,060**	**534,577**	**219,117**	**(2,462)**	**1,004,292**
Net income after dividends on preference stock	**-**	**-**	**-**	**121,511**	**-**	**121,511**
Issuance of common stock	**500**	**50,000**	**-**	**-**	**-**	**50,000**
Capital contributions from parent company	**-**	**-**	**3,798**	**-**	**-**	**3,798**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**(265)**	**(265)**
Cash dividends on common stock	**-**	**-**	**-**	**(104,300)**	**-**	**(104,300)**
Balance at December 31, 2010	**3,643**	**$303,060**	**$538,375**	**$236,328**	**$(2,727)**	**$1,075,036**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2010, 2009, and 2008

Gulf Power Company 2010 Annual Report

	2010	2009	2008
		(in thousands)	
Net income after dividends on preference stock	**$121,511**	$111,233	$98,345
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(542), $1,132, and $(1,077), respectively	**(863)**	1,803	(1,716)
Reclassification adjustment for amounts included in net income, net of tax of $376, $419, and $366, respectively	**598**	667	583
Total other comprehensive income (loss)	**(265)**	2,470	(1,133)
Comprehensive Income	**$121,246**	$113,703	$97,212

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

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

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statement 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 operations. Costs for these services amounted to $99 million, $87 million, and $86 million during 2010, 2009, and 2008, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission (SEC) prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has 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 $8.9 million, $3.9 million, and $8.1 million and Mississippi Power $25.0 million, $20.9 million, and $22.8 million in 2010, 2009, and 2008, 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. Expenses associated with the PPA were $14.7 million, $13.2 million, and none in 2010, 2009, and 2008, respectfully. These costs have been approved for recovery by the Florida PSC through the Company's purchase power capacity cost recovery clause. 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, 2010 and 2009, respectfully. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $135 million for the entire project. These costs are estimated to begin in 2012 and will continue through 2023. These costs have been approved for recovery by the Florida PSC through the Company's purchase power capacity cost recovery clause and by FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2010, 2009, or 2008.

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

In 2010, the Company purchased an assembly fluted compressor from Georgia Power and an unbucketed turbine rotor from Southern Power for $3.9 million and $6.3 million, respectively. The Company also sold a universal distance piece to Southern Power, a compressor rotor and blades to Georgia Power and a turbine rotor and blades to Mississippi Power for $0.6 million, $3.9 million, and $6.2 million, respectively. There were no significant affiliate transactions for 2009. In 2008, the Company sold a turbine rotor assembly and a distance piece component to Southern Power for $9.4 million and $0.7 million, respectively. These affiliate transactions were made in accordance with FERC and state PSC rules and guidelines.

Regulatory Assets and Liabilities

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

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

	2010	2009	Note
	(in thousands)		
Deferred income tax charges	**$ 42,352**	$ 39,018	(a)
Deferred income tax charges – Medicare subsidy	**4,332**	-	(b)
Asset retirement obligations	**(4,310)**	(4,371)	(a,j)
Other cost of removal obligations	**(204,408)**	(191,248)	(a)
Deferred income tax credits	**(9,362)**	(11,412)	(a)
Loss on reacquired debt	**15,874**	14,599	(c)
Vacation pay	**8,288**	8,120	(d,j)
Under recovered regulatory clause revenues	**17,437**	2,384	(e)
Over recovered regulatory clause revenues	**(17,703)**	(14,510)	(e)
Property damage reserve	**(27,593)**	(24,046)	(f)
Fuel-hedging (realized and unrealized) losses	**15,024**	15,367	(g,j)
Fuel-hedging (realized and unrealized) gains	**(2,376)**	(190)	(g,j)
PPA charges	**52,404**	8,141	(j,k)
Generation site selection/evaluation costs	**12,814**	8,373	(l)
Other assets	**833**	131	(e,j)
Environmental remediation	**61,749**	65,223	(h,j)
PPA credits	**(7,536)**	(7,536)	(j,k)
Other liabilities	**(930)**	(715)	(f)
Retiree benefit plans, net	**74,930**	91,055	(i,j)
Total assets (liabilities), net	**$ 31,819**	$ (1,617)	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.
(b) Recovered and amortized over periods not exceeding 14 years. See Note 5 under “Current and Deferred Income Taxes” for additional information.
(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.
(d) Recorded as earned by employees and recovered as paid, generally within one year.
(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.
(f) Recorded and recovered or amortized as approved by the Florida PSC.
(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the fuel cost recovery clause.
(h) Recovered through the environmental cost recovery clause when the remediation is performed.
(i) Recovered and amortized over the average remaining service period which may range up to 15 years. Includes $166 thousand related to other postretirement benefits. See Note 2 and Note 5 for additional information.
(j) Not earning a return as offset in rate base by a corresponding asset or liability.
(k) Recovered over the life of the PPA for periods up to 14 years.
(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

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

Revenues

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

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emissions allowances as they are used.

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 regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

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

	2010	2009
	(in thousands)	
Generation	**$ 2,157,619**	$ 2,034,826
Transmission	**337,055**	317,298
Distribution	**982,022**	938,393
General	**154,762**	136,934
Plant acquisition adjustment	**2,797**	3,052
Total plant in service	**$ 3,634,255**	$ 3,430,503

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2010, 3.1% in 2009, and 3.4% in 2008. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

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

The liability recognized to retire long-lived assets 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:

	2010	2009
	(in thousands)	
Balance at beginning of year	**$ 12,608**	$ 12,042
Liabilities incurred	**-**	224
Liabilities settled	**(1,794)**	(300)
Accretion	**656**	642
Cash flow revisions	**-**	-
Balance at end of year	**$ 11,470**	$ 12,608

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 7.65% for each of the years 2010, 2009, and 2008. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 7.39%, 26.64%, and 12.62% for 2010, 2009, and 2008, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC-approved annual accrual to the property damage reserve is \$3.5 million, with a target level for the reserve between \$25.1 million and \$36.0 million. The Florida PSC also authorized the Company to make additional accruals above the \$3.5 million at the Company's discretion. The Company accrued total expenses of \$3.5 million in 2010, \$3.5 million in 2009, and \$3.5 million in 2008. As of December 31, 2010 and 2009, the balance in the Company's property damage reserve totaled approximately \$27.6 million and \$24.0 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. According to the 2006 Florida PSC order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of \$10 million during any calendar year, the Company will 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.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to \$1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above \$1.6 million to the extent the balance in the reserve does not exceed \$2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was \$2.0 million and \$2.9 million at December 31, 2010 and 2009, respectively. For 2010, \$1.6 million and \$0.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2009, \$1.6 million and \$1.3 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. Liabilities in excess of the reserve balance of \$0.8 million and \$0.1 million at December 31, 2010 and 2009, respectively, are included in deferred credits and other liabilities in the balance sheets. Corresponding regulatory assets of \$0.8 million and \$0.1 million at December 31, 2010 and 2009, respectively, are included in current assets in the balance sheets.

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 costs of oil, coal, natural gas, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the 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 exemption, 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 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 has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2010.

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 2010, the Company contributed approximately $28 million to the qualified pension plan. No contributions to the qualified pension plan are expected for the year ending December 31, 2011. 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 post retirement trusts to the extent required by the FERC. For the year ending December 31, 2011, 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 2007 for the 2008 plan year using a discount rate of 6.30% and an annual salary increase of 3.75%.

	2010	2009	2008
Discount rate:			
Pension plans	**5.53%**	5.93%	6.75%
Other postretirement benefit plans	**5.41**	5.84	6.75
Annual salary increase	**3.84**	4.18	3.75
Long-term return on plan assets:			
Pension plans	**8.75**	8.50	8.50
Other postretirement benefit plans	**8.18**	8.36	8.38

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) was a weighted average medical care cost trend rate of 8.25% for 2011, decreasing gradually to 5.00% through the year 2019 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2010 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,802	$ 3,246
Service and interest costs	205	175

Pension Plans

The total accumulated benefit obligation for the pension plans was $290 million in 2010 and $275 million in 2009. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 298,886**	$ 260,765
Service cost	**7,853**	6,478
Interest cost	**17,305**	17,139
Benefits paid	**(13,401)**	(12,884)
Plan amendments	**460**	-
Actuarial loss (gain)	**5,183**	27,388
Balance at end of year	**316,286**	298,886
Change in plan assets		
Fair value of plan assets at beginning of year	**254,059**	229,407
Actual return (loss) on plan assets	**38,736**	36,840
Employer contributions	**28,434**	696
Benefits paid	**(13,401)**	(12,884)
Fair value of plan assets at end of year	**307,828**	254,059
Accrued liability	**$ (8,458)**	$ (44,827)

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $300 million and $16 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2010 and 2009 related to the Company's pension plans consist of the following:

	2010	2009
	(in thousands)	
Prepaid pension costs	**$ 7,291**	$ -
Other regulatory assets	**75,096**	85,194
Current liabilities, other	**(778)**	(910)
Employee benefit obligations	**(14,971)**	(43,917)

Presented below are the amounts included in regulatory assets at December 31, 2010 and 2009 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 2011.

	2010	2009	Estimated Amortization in 2011
		(in thousands)	
Prior service cost	**$ 7,664**	$ 8,506	$ 1,262
Net (gain) loss	**67,432**	76,688	512
Other regulatory assets, deferred	**$ 75,096**	$ 85,194	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2010 and 2009 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2008	$ 71,990
Net loss	14,906
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	(1,478)
Amortization of net gain	(224)
Total reclassification adjustments	(1,702)
Total change	13,204
Balance at December 31, 2009	**85,194**
Net (gain)	**(8,857)**
Change in prior service costs	**459**
Reclassification adjustments:	
Amortization of prior service costs	**(1,302)**
Amortization of net gain	**(398)**
Total reclassification adjustments	**(1,700)**
Total change	**(10,098)**
Balance at December 31, 2010	**$ 75,096**

Components of net periodic pension cost were as follows:

	2010	2009	2008
		(in thousands)	
Service cost	**$ 7,853**	$ 6,478	$ 6,750
Interest cost	**17,305**	17,139	15,475
Expected return on plan assets	**(24,695)**	(24,357)	(23,757)
Recognized net (gain) loss	**398**	224	334
Net amortization	**1,302**	1,478	1,478
Net periodic pension cost	**$ 2,163**	$ 962	$ 280

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, 2010, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2011	$ 14,524
2012	15,129
2013	15,709
2014	16,419
2015	17,158
2016 to 2020	99,482

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 72,640**	$ 72,391
Service cost	**1,304**	1,328
Interest cost	**4,121**	4,705
Benefits paid	**(4,068)**	(4,115)
Actuarial (gain) loss	**(4,704)**	497
Plan amendments	**-**	(2,416)
Retiree drug subsidy	**324**	250
Balance at end of year	**69,617**	72,640
Change in plan assets		
Fair value of plan assets at beginning of year	**14,973**	13,180
Actual return (loss) on plan assets	**2,010**	2,735
Employer contributions	**2,458**	2,923
Benefits paid	**(3,744)**	(3,865)
Fair value of plan assets at end of year	**15,697**	14,973
Accrued liability	**$ (53,920)**	$ (57,667)

Amounts recognized in the balance sheets at December 31, 2010 and 2009 related to the Company's other postretirement benefit plans consist of the following:

	2010	2009
	(in thousands)	
Regulatory assets	**$ -**	$ 5,861
Regulatory liabilities	**(166)**	-
Current liabilities, other	**(211)**	-
Employee benefit obligations	**(53,709)**	(57,667)

Presented below are the amounts included in regulatory assets at December 31, 2010 and 2009 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 2011.

	2010	2009	**Estimated Amortization in 2011**
		(in thousands)	
Prior service cost	**$ 695**	$ 881	**$ 186**
Net (gain) loss	**(1,311)**	4,273	**(47)**
Transition obligation	**450**	707	**257**
Regulatory assets (liabilities)	**$ (166)**	$ 5,861	

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, 2010 and 2009 are presented in the following table:

	Regulatory Assets	**Regulatory Liabilities**
	(in thousands)	
Balance at December 31, 2008	$ 9,922	$ -
Net gain	(1,097)	-
Change in prior service costs/transition obligation	(2,416)	-
Reclassification adjustments:		
Amortization of transition obligation	(323)	-
Amortization of prior service costs	(293)	-
Amortization of net gain	68	-
Total reclassification adjustments	(548)	-
Total change	(4,061)	-
Balance at December 31, 2009	$ 5,861	$ -
Net gain	**(5,455)**	**(166)**
Change in prior service costs/transition obligation	**-**	**-**
Reclassification adjustments:		
Amortization of transition obligation	**(257)**	**-**
Amortization of prior service costs	**(186)**	**-**
Amortization of net gain	**37**	**-**
Total reclassification adjustments	**(406)**	**-**
Total change	**(5,861)**	**(166)**
Balance at December 31, 2010	**$ -**	**$ (166)**

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

	2010	2009	2008
		(in thousands)	
Service cost	**$ 1,304**	$ 1,328	$ 1,413
Interest cost	**4,121**	4,705	4,536
Expected return on plan assets	**(1,481)**	(1,436)	(1,452)
Net amortization	**406**	548	702
Net postretirement cost	**$ 4,350**	$ 5,145	$ 5,199

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2010, 2009, and 2008 by approximately $1.0 million, $1.3 million, and $1.4 million, respectively, and is expected to have a similar impact on future expenses.

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 Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2011	$ 4,461	$ (372)	$ 4,089
2012	4,706	(423)	4,283
2013	4,931	(477)	4,454
2014	5,177	(531)	4,646
2015	5,372	(589)	4,783
2016 to 2020	27,974	(3,023)	24,951

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2010 and 2009, along with the targeted mix of assets for each plan, is presented below:

	Target	**2010**	2009
Pension plan assets:			
Domestic equity	29%	**29%**	33%
International equity	28	**27**	29
Fixed income	15	**22**	15
Special situations	3	**-**	-
Real estate investments	15	**13**	13
Private equity	10	**9**	10
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	28%	**28%**	32%
International equity	27	**26**	28
Domestic fixed income	18	**25**	18
Special situations	3	**-**	-
Real estate investments	14	**12**	12
Private equity	10	**9**	10
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 an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Though currently unfunded, established both to execute opportunistic investment strategies with the objectives of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as to invest 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, 2010 and 2009. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

The fair values of pension plan assets as of December 31, 2010 and 2009 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

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

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

As of December 31, 2009:	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*	$ 50,434	$ 20,856	$ -	$ 71,290
International equity*	65,197	6,497	-	71,694
Fixed income:				
U.S. Treasury, government, and agency bonds	-	18,783	-	18,783
Mortgage- and asset-backed securities	-	5,107	-	5,107
Corporate bonds	-	12,589	-	12,589
Pooled funds	-	455	-	455
Cash equivalents and other	126	15,396	-	15,522
Special situations	-	-	-	-
Real estate investments	7,862	-	24,699	32,561
Private equity	-	-	25,053	25,053
Total	$ 123,619	$ 79,683	$ 49,752	$ 253,054
Liabilities:				
Derivatives	(202)	(51)	-	(253)
Total	$ 123,417	$ 79,632	$ 49,752	$ 252,801

*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, 2010 and 2009 are as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in thousands)			
Beginning balance	**$ 24,699**	**$ 25,053**	$ 37,790	$ 22,063
Actual return on investments:				
Related to investments held at year end	**2,596**	**2,954**	(10,741)	1,724
Related to investments sold during the year	**810**	**810**	(2,938)	452
Total return on investments	**3,406**	**3,764**	(13,679)	2,176
Purchases, sales, and settlements	**2,250**	**(90)**	588	814
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 30,355**	**$ 28,727**	$ 24,699	$ 25,053

The fair values of other postretirement benefit plan assets as of December 31, 2010 and 2009 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

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

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

As of December 31, 2009:	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*	$ 2,706	$ 1,119	$ -	$ 3,825
International equity*	3,499	348	-	3,847
Fixed income:				
U.S. Treasury, government, and agency bonds	-	1,008	-	1,008
Mortgage- and asset-backed securities	-	274	-	274
Corporate bonds	-	675	-	675
Pooled funds	-	553	-	553
Cash equivalents and other	8	827	-	835
Special situations	-	-	-	-
Real estate investments	420	-	1,326	1,746
Private equity	-	-	1,346	1,346
Total	$ 6,633	$ 4,804	$ 2,672	$ 14,109
Liabilities:				
Derivatives	(11)	(3)	-	(14)
Total	$ 6,622	$ 4,801	$ 2,672	$ 14,095

*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, 2010 and 2009 are as follows:

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$ 1,326**	**$ 1,346**	$ 2,073	$ 1,211
Actual return on investments:				
Related to investments held at year end	**30**	**-**	(624)	68
Related to investments sold during the year	**40**	**34**	(154)	25
Total return on investments	**70**	**34**	(778)	93
Purchases, sales, and settlements	**56**	**(5)**	31	42
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$ 1,452**	**$ 1,375**	$ 1,326	$ 1,346

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 2010, 2009, and 2008 were $3.6 million, $3.7 million, and $3.5 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 opacity and air and water quality standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including 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. 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. After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power, including one facility co-owned by the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. In July 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power with respect to its other affected units regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. On September 2, 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims for summary disposition or trial. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

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

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005 and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. In November 2009, the plaintiffs filed an appeal with the U.S. Court of Appeals for the Ninth Circuit challenging the district court's order dismissing the case. On January 24, 2011, the defendants filed a motion with the U.S. Court of Appeals for the Ninth Circuit to defer scheduling the case pending the decision of the U.S. Supreme Court in the New York case discussed above. The ultimate outcome of this matter cannot be determined at this time.

Other Litigation

Common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas emissions have become more frequent, and, as illustrated by the New York and Kivalina cases, courts have been debating whether private parties and states have standing to bring such claims. In another common law nuisance case, the U.S. District Court for the Southern District of Mississippi dismissed private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. The court ruled that the parties lacked standing to bring the claims and the claims were barred by the political question doctrine. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the district court and held that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and none of the claims were barred by the political question doctrine. On May 28, 2010, however, the U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal of the case based on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the U.S. Supreme Court denied the plaintiffs' petition to reinstate the appeal. This case is now concluded.

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's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $61.7 million as of December 31, 2010. 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 is no impact to net income as a result of these liabilities.

The final outcome of these matters cannot now be determined. 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.

Income Tax Matters

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $8 million for the Company. Although IRS approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. See Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

General

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.

In November 2010, the Florida PSC approved the Company's annual cost recovery clause requests for its fuel, purchased power capacity, energy conservation, and environmental compliance cost recovery factors for 2011. The net effect of the approved changes to the Company's cost recovery factors for 2011 is a 2.8% rate decrease for residential customers using 1,000 kilowatt-hours per month. The billing factors for 2011 are intended to allow the Company to recover projected 2011 costs as well as refund or collect the 2010 over or under recovered amounts in 2011. 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, changing the billing factors has no significant effect on the Company's revenues or net income, but does impact annual cash flow.

Fuel Cost Recovery

The Company petitions for fuel cost recovery rates to be approved by the Florida PSC on an annual basis. The fuel cost recovery rates include the costs of fuel and purchased energy. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. If, at any time during the year, the projected 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. The change in the fuel cost under-recovered balance during 2010 was primarily due to higher than expected fuel costs and purchased power energy expenses. At December 31, 2010 and 2009, the under recovered fuel balance was approximately $17.4 million and $2.4 million, respectively, which is included in under recovered regulatory clause revenues, current in the balance sheets.

Purchased Power Capacity Recovery

The Florida PSC allows the Company to recover its costs for capacity purchased from other power producers under PPAs through a separate cost recovery component or factor in the Company's retail energy rates. Like the other specific cost recovery factors included in the Company's retail energy rates, the rates for purchased capacity are set annually. When the Company enters into a new PPA, it is reviewed and approved by the Florida PSC for cost recovery purposes. As of December 31, 2010 and 2009, the Company had an over recovered purchased power capacity balance of approximately $4.4 million and $1.5 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emission allowance expense, depreciation, and a return on invested capital. 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 August 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplates implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that are scheduled to be implemented in the 2007 through 2011 timeframe. On April 1, 2010, the Company filed an update to the plan, which was approved by the Florida PSC on November 15, 2010. The Florida PSC acknowledged that the costs associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2010 and 2009, the over recovered environmental balance was approximately $10.4 million and $11.7 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

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

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

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.
At December 31, 2010, 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	$ 285,923[a]	$ 267,527
Accumulated depreciation	104,492	155,672
Construction work in progress	72,250	137
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.8 million.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in thousands)	
Federal –			
Current	**$ (14,115)**	$ 62,980	$ 26,592
Deferred	**77,452**	(14,453)	21,481
	63,337	48,527	48,073
State –			
Current	**2,948**	6,590	3,563
Deferred	**5,229**	(2,092)	2,467
	8,177	4,498	6,030
Total	**$ 71,514**	$ 53,025	$ 54,103

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:

	2010	2009
	(in thousands)	
Deferred tax liabilities–		
Accelerated depreciation	**$ 413,490**	$ 332,971
Fuel recovery clause	**7,062**	965
Pension and other employee benefits	**23,990**	15,539
Regulatory assets associated with employee benefit obligations	**29,054**	37,768
Regulatory assets associated with asset retirement obligations	**4,646**	5,106
Other	**15,793**	9,084
Total	**494,035**	401,433
Deferred tax assets–		
Federal effect of state deferred taxes	**14,757**	13,076
Postretirement benefits	**20,723**	18,465
Pension and other employee benefits	**33,047**	41,124
Property reserve	**12,712**	10,642
Other comprehensive loss	**1,712**	1,546
Asset retirement obligations	**4,646**	5,106
Other	**19,727**	16,995
Total	**107,324**	106,954
Net deferred tax liabilities	**386,711**	294,479
Less current portion, net	**(3,835)**	2,926
Accumulated deferred income taxes	**$ 382,876**	$ 297,405

At December 31, 2010, the tax-related regulatory assets to be recovered from customers was $42.4 million. These assets are attributable to tax benefits 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 allowance for funds used during construction. At December 31, 2010, the tax-related regulatory liabilities to be credited to customers was $9.4 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits. In 2010, the Company deferred $4.5 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of health care costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to amortization expense over the remaining average service life of 14 years. Amortization amounted to $0.2 million in 2010.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.5 million in 2010, $1.6 million in 2009, and $1.7 million in 2008. At December 31, 2010, all investment tax credits available to reduce federal income taxes payable had been utilized.

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts in 2010 significantly increased deferred income tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.7**	1.7	2.5
Non-deductible book depreciation	**0.3**	0.3	-
Difference in prior years' deferred and current tax rate	**(0.3)**	(0.4)	(0.5)
Production activities deduction	**-**	(0.9)	0.1
AFUDC equity	**(1.3)**	(4.9)	(2.2)
Other, net	**(0.5)**	0.3	(0.8)
Effective income tax rate	**35.9%**	31.1%	34.1%

The increase in the 2010 effective tax rate is primarily the result of a decrease in AFUDC equity, which is not taxable.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage was phased in over the years 2005 through 2010. For 2008 and 2009 a 6% reduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation and pension contributions there was no domestic production deduction available to the Company for 2010.

Unrecognized Tax Benefits

For 2010, the total amount of unrecognized tax benefits increased by $2.2 million, resulting in a balance of $3.9 million as of December 31, 2010.

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

	2010	2009	2008
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$1,639**	$ 294	$ 887
Tax positions from current periods	**1,027**	455	93
Tax positions from prior periods	**1,204**	890	11
Reductions due to settlements	**-**	-	(697)
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$ 3,870**	$ 1,639	$ 294

The tax positions increase from current periods relates primarily to the tax accounting method change for repairs tax position and other miscellaneous uncertain tax positions. The tax positions increase from prior periods relates primarily to the tax accounting method change for repairs; and other miscellaneous uncertain tax positions. See Note 3 under "Income Tax Matters" for additional information.

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

	2010	2009	2008
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 1,826**	$ 1,639	$ 294
Tax positions not impacting the effective tax rate	**2,044**	-	-
Balance of unrecognized tax benefits	**$ 3,870**	$ 1,639	$ 294

The tax positions impacting the effective tax rate relate primarily to the production activities deduction. The tax positions not impacting the effective tax rate relate to the timing difference associated with the tax accounting method change for repairs. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See Note 3 under "Income Tax Matters" for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2010	2009	2008
		(in thousands)	
Interest accrued at beginning of year	**$ 90**	$ 17	$ 58
Interest reclassified due to settlements	**-**	-	(54)
Interest accrued during the year	**120**	73	13
Balance at end of year	**$ 210**	$ 90	$ 17

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The conclusion or settlement of state audits could also impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

6. FINANCING

Securities Due Within One Year

At December 31, 2010, the Company had a $110 million bank loan that will mature on April 8, 2011.

Senior Notes

At December 31, 2010 and 2009, the Company had a total of $812.0 million and $727.5 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company which totaled approximately $41 million at December 31, 2010.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. At December 31, 2010 and 2009, the Company had a total of $309 million and $288 million of outstanding pollution control revenue bonds, respectively, and is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2010. 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.

On January 25, 2010, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. On January 20, 2011, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

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, 2010, the Company had $240 million of lines of credit with banks, all of which remained unused. These bank credit arrangements will expire in 2011 and $210 million contain provisions allowing one-year term loans executable at expiration. Of the $240 million, $69 million provides support for variable rate pollution control revenue bonds and $171 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. In February 2011, the Company renewed a $30 million credit facility. Commitment fees average less than ⅜ of 1% for the Company.

Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65%, as defined in the arrangements. At December 31, 2010, the Company was in compliance with these covenants.

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

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. At December 31, 2010, the Company had $92.0 million of commercial paper outstanding. At December 31, 2009, the Company had $88.9 million of commercial paper outstanding.

During 2010, the maximum amount outstanding for commercial paper was $108 million, and the average amount outstanding was $44 million. The maximum amount outstanding for commercial paper in 2009 was $152.1 million and the average amount outstanding was $51.7 million. The weighted average annual interest rate on commercial paper was 0.3% and 1.0% for 2010 and 2009, respectively.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $381.5 million in 2011, $395.5 million in 2012, and $384.1 million in 2013. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $175.9 million, $227.8 million, and $214.0 million for 2011, 2012, and 2013, respectively. 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; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. The Company does not have any significant new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for a combined cycle generating facility. The LTSA provides that GE will perform all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in the LTSA.

In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under the LTSA for facilities owned are currently estimated at $50.5 million over the remaining life of the LTSA, which is currently estimated to be up to seven years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made under the LTSA prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in deferred charges and other assets in the balance sheets for 2010 and current assets and deferred charges and other assets in the balance sheets for 2009. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 0.8 million tons, equating to approximately $63 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $6.4 million in 2011, $6.5 million in 2012, $6.7 million in 2013, $6.9 million in 2014, and $7.0 million in 2015. Limestone costs are recovered through the environmental cost recovery clause.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2010. Also, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Total estimated minimum long-term obligations at December 31, 2010 were as follows:

	Commitments		
	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2011	$ 40,911	$ 104,977	$ 312,244
2012	41,327	86,108	119,773
2013	45,449	75,304	-
2014	66,812	86,101	-
2015	92,843	79,294	-
2016 and thereafter	685,750	209,308	-
Total	$ 973,092	$ 641,092	$ 432,017

*Included above is $186.6 million in obligations with affiliated companies. Certain PPAs are accounted for as operating leases.

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

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

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Rental expenses related to these operating leases totaled $23.1 million, $10.1 million, and $5.0 million for 2010, 2009, and 2008, respectively.

At December 31, 2010, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Barges & Rail Cars	Other	Total
		(in thousands)	
2011	$ 18,482	$ 2,147	$ 20,629
2012	16,608	452	17,060
2013	15,529	233	15,762
2014	14,385	131	14,516
2015	554	-	554
2016 and thereafter	1,045	-	1,045
Total	$ 66,603	$ 2,963	$ 69,566

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum rail cars for the transportation of coal to Plant Daniel. The Company has the option to purchase the rail cars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other rail cars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $3.5 million in 2010, $4.0 million in 2009, and $4.0 million in 2008. The Company's annual railcar lease payments for 2011 through 2015 will average approximately $1.1 million and after 2015, lease payments total in aggregate approximately $1.0 million.

The Company has other operating lease agreements for aluminum rail cars for transportation of coal to Plant Scholtz and to the Alabama State Docks located in Mobile, Alabama. At the Alabama State Docks this coal is transferred from the railcar to barge for transportation to Plant Crist and Plant Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $3.9 million in 2010, $4.0 million in 2009, and none in 2008. The Company's annual railcar lease payments for 2011 through 2013 will average approximately $2.1 million.

The Company entered into operating lease agreements for barges and tow boats for the transport of coal to Plants Crist and Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $13.5 million in 2010 and none in both 2009 and 2008. The Company's annual barge and tow boat lease payments for 2011 through 2014 will average approximately $13.4 million.

8. STOCK COMPENSATION

Stock Option Plan

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2010, there were 290 current and former employees of the Company participating in the stock option plan, and there were 10 million shares of Southern Company common stock remaining available for awards under this plan and the Performance Share Plan discussed below. 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 stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2010, 2009, and 2008 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	**2010**	2009	2008
Expected volatility	**17.4%**	15.6%	13.1%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.4%**	1.9%	2.8%
Dividend yield	**5.6%**	5.4%	4.5%
Weighted average grant-date fair value	**$2.23**	$1.80	$2.37

The Company's activity in the stock option plan for 2010 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2009	1,658,121	$ 32.28
Granted	324,919	31.18
Exercised	(246,822)	29.50
Cancelled	(253)	30.17
Outstanding at December 31, 2010	**1,735,965**	**$ 32.47**
Exercisable at December 31, 2010	**1,056,570**	**$ 32.92**

The number of stock options vested, and expected to vest in the future, as of December 31, 2010 was not significantly different from the number of stock options outstanding at December 31, 2010 as stated above. As of December 31, 2010, 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 $10.0 million and $5.6 million, respectively.

As of December 31, 2010, 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, 2010, 2009, and 2008, total compensation cost for stock option awards recognized in income was $0.8 million, $0.9 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.4 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, 2010, 2009, and 2008 was $1.6 million, $0.2 million, and $1.3 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $0.6 million, $0.1 million, and $0.5 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Performance Share Plan

In 2010, Southern Company implemented the performance share program under its omnibus incentive compensation plan, which provides performance share award units to a large segment of its employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model of 20.7% was based on historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of the grant was $1.75. During 2010, 35,933 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 365 performance share units were forfeited by the Company's employees resulting in 35,568 unvested units outstanding at December 31, 2010.

For the year ended December 31, 2010, the Company's total compensation cost for performance share units recognized in income was $0.3 million, with the related tax benefit also recognized in income of $0.1 million. As of December 31, 2010, there was $0.6 million of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years.

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ -	$ 2,380	$ -	$ 2,380
Cash equivalents	11,770	-	-	11,770
Total	$ 11,770	$ 2,380	$ -	$ 14,150
Liabilities:				
Energy-related derivatives	$ -	$13,608	$ -	$ 13,608

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 10 for additional information on how these derivatives are used.

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

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

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

As of December 31, 2010 and 2009, 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:		
2010	**$ 1,224,398**	**$ 1,258,428**
2009	$ 1,118,914	$ 1,137,761

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

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, and recently has started using financial options 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, 2010, 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)		
19,620	2015	-

*mmBtu - million British thermal units

Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

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

For the year ended December 31, 2010, the Company had realized net gains of $1.5 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedge transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 are $0.9 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2010 and 2009, the fair value of energy-related derivatives and interest rate derivatives were reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 1,801**	$ 142	Liabilities from risk management activities	**$ 9,415**	$ 9,442
	Other deferred charges and assets	**575**	48	Other deferred credits and liabilities	**4,193**	4,447
Total derivatives designated as hedging instruments for regulatory purposes		**$ 2,376**	$ 190		**$ 13,608**	$ 13,889
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ -**	$ 2,934	Liabilities from risk management activities	**$ -**	$ -
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ 4**	$ 12	Liabilities from risk management activities	**$ -**	$ -
Total		**$ 2,380**	$ 3,136		**$ 13,608**	$ 13,889

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

At December 31, 2010 and 2009, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (9,415)**	$ (9,442)	Other regulatory liabilities, current	**$ 1,801**	$142
	Other regulatory assets, deferred	**(4,193)**	(4,447)	Other regulatory liabilities, deferred	**575**	48
Total energy-related derivative gains (losses)		**$ (13,608)**	$ (13,889)		**$ 2,376**	$190

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2010**	2009	2008	**Statements of Income Location**	**2010**	2009	2008
		(in thousands)				*(in thousands)*	
Interest rate derivatives	**$ (1,405)**	$2,934	$(2,792)	Interest expense, net of amounts capitalized	**$ (974)**	$ (1,085)	$(949)

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

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2010, the fair value of derivative liabilities with contingent features was $0.8 million.

At December 31, 2010, 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, is $40.0 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 data for 2010 and 2009 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2010	**$ 356,712**	**$ 52,430**	**$ 25,300**
June 2010	**403,171**	**65,066**	**32,317**
September 2010	**483,455**	**82,896**	**42,907**
December 2010	**346,871**	**46,408**	**20,987**
March 2009	$ 284,284	$ 30,914	$ 16,542
June 2009	341,095	54,320	32,269
September 2009	377,641	67,392	41,208
December 2009	299,209	36,036	21,214

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

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SELECTED FINANCIAL AND OPERATING DATA 2006-2010
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	2010	2009	2008	2007	2006
Operating Revenues (in thousands)	**$1,590,209**	$1,302,229	$1,387,203	$1,259,808	$1,203,914
Net Income after Dividends on Preference Stock (in thousands)	**$121,511**	$111,233	$98,345	$84,118	$75,989
Cash Dividends on Common Stock (in thousands)	**$104,300**	$89,300	$81,700	$74,100	$70,300
Return on Average Common Equity (percent)	**11.69**	12.18	12.66	12.32	12.29
Total Assets (in thousands)	**$3,584,939**	$3,293,607	$2,879,025	$2,498,987	$2,340,489
Gross Property Additions (in thousands)	**$285,379**	$450,421	$390,744	$239,337	$147,086
Capitalization (in thousands):					
Common stock equity	**$1,075,036**	$1,004,292	$822,092	$731,255	$634,023
Preference stock	**97,998**	97,998	97,998	97,998	53,887
Long-term debt	**1,114,398**	978,914	849,265	740,050	696,098
Total (excluding amounts due within one year)	**$2,287,432**	$2,081,204	$1,769,355	$1,569,303	$1,384,008
Capitalization Ratios (percent):					
Common stock equity	**47.0**	48.3	46.5	46.6	45.8
Preference stock	**4.3**	4.7	5.5	6.2	3.9
Long-term debt	**48.7**	47.0	48.0	47.2	50.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**376,561**	374,091	373,595	373,036	364,647
Commercial	**53,263**	53,272	53,548	53,838	53,466
Industrial	**272**	279	287	298	295
Other	**562**	512	499	491	484
Total	**430,658**	428,154	427,929	427,663	418,892
Employees (year-end)	**1,330**	1,365	1,342	1,324	1,321

	2010	2009	2008	2007	2006
Operating Revenues (in thousands)**:**					
Residential	**$707,196**	$588,073	$581,723	$537,668	$510,995
Commercial	**439,468**	376,125	369,625	329,651	305,049
Industrial	**157,591**	138,164	165,564	135,179	132,339
Other	**4,471**	4,206	3,854	3,831	3,655
Total retail	**1,308,726**	1,106,568	1,120,766	1,006,329	952,038
Wholesale - non-affiliates	**109,172**	94,105	97,065	83,514	87,142
Wholesale - affiliates	**110,051**	32,095	106,989	113,178	118,097
Total revenues from sales of electricity	**1,527,949**	1,232,768	1,324,820	1,203,021	1,157,277
Other revenues	**62,260**	69,461	62,383	56,787	46,637
Total	**$1,590,209**	$1,302,229	$1,387,203	$1,259,808	$1,203,914
Kilowatt-Hour Sales (in thousands)**:**					
Residential	**5,651,274**	5,254,491	5,348,642	5,477,111	5,425,491
Commercial	**3,996,502**	3,896,105	3,960,923	3,970,892	3,843,064
Industrial	**1,685,817**	1,727,106	2,210,597	2,048,389	2,136,439
Other	**25,602**	25,121	23,237	24,496	23,886
Total retail	**11,359,195**	10,902,823	11,543,399	11,520,888	11,428,880
Wholesale - non-affiliates	**1,675,079**	1,813,592	1,816,839	2,227,026	2,079,165
Wholesale - affiliates	**2,436,883**	870,470	1,871,158	2,884,440	2,937,735
Total	**15,471,157**	13,586,885	15,231,396	16,632,354	16,445,780
Average Revenue Per Kilowatt-Hour (cents)**:**					
Residential	**12.51**	11.19	10.88	9.82	9.42
Commercial	**11.00**	9.65	9.33	8.30	7.94
Industrial	**9.35**	8.00	7.49	6.60	6.19
Total retail	**11.52**	10.15	9.71	8.73	8.33
Wholesale	**5.33**	4.70	5.53	3.85	4.09
Total sales	**9.88**	9.07	8.70	7.23	7.04
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,036**	14,049	14,274	14,755	15,032
Residential Average Annual Revenue Per Customer	**$1,882**	$1,572	$1,552	$1,448	$1,416
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,663**	2,659	2,659	2,659	2,659
Maximum Peak-Hour Demand (megawatts)**:**					
Winter	**2,544**	2,310	2,360	2,215	2,195
Summer	**2,519**	2,538	2,533	2,626	2,479
Annual Load Factor (percent)	**56.1**	53.8	56.7	55.0	57.9
Plant Availability Fossil-Steam (percent)	**94.7**	89.7	88.6	93.4	91.3
Source of Energy Supply (percent)**:**					
Coal	**64.6**	61.7	77.3	81.8	82.5
Gas	**17.8**	28.0	15.3	13.6	12.4
Purchased power -					
From non-affiliates	**13.2**	2.2	2.6	1.6	1.9
From affiliates	**4.4**	8.1	4.8	3.0	3.2
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Gulf Power Company 2010 Annual Report

DIRECTORS

Susan N. Story (1)
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2003

Mark A. Crosswhite (2)
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2010

C. LeDon Anchors (3)
Attorney at Law
Anchors Smith Grimsley
A Professional Limited Company
Fort Walton Beach, Florida. Elected 2001

Allan G. Bense (4)
Chairman and Chief Executive Officer
Bense Enterprises, Inc.
Panama City, Florida. Elected 2010

Deborah H. Calder (5)
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

Fred C. Donovan, Sr. (6)
Chairman and Chief Executive Officer
Baskerville-Donovan, Inc.
Pensacola, Florida. Elected 1991

J. Mort O'Sullivan, III (7)
Managing Partner
O'Sullivan Creel LLP
Pensacola, Florida. Elected 2010

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

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

OFFICERS

Susan N. Story (1)
President and Chief Executive Officer
28 Years of Service

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

Michael L. Burroughs (8)
Vice President – Sr. Production Officer
19 Years of Service

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

Theodore J. McCullough (9)
Vice President – Sr. Production Officer
24 Years of Service

Philip C. Raymond (10)
Vice President and Chief Financial Officer
19 Years of Service

Richard S. Teel (11)
Vice President and Chief Financial Officer
11 Years of Service

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

DIRECTORS AND OFFICERS (continued)
Gulf Power Company 2010 Annual Report

Connie J. Erickson
Comptroller
8 Years of Service

Susan D. Ritenour
Secretary and Treasurer
29 Years of Service

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

Marsha S. Johnson (12)
Vice President
25 Years of Service

Stacy R. Kilcoyne (13)
Vice President
33 Years of Service

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

(1) Resigned effective December 31, 2010. Transferred to Southern Company Services.
(2) Elected effective January 1, 2011.
(3) Retired effective March 22, 2010.
(4) Elected effective April 22, 2010.
(5) Elected effective April 22, 2010.
(6) Retired effected August 4, 2010.
(7) Elected effective June 29, 2010.
(8) Elected effective August 1, 2010.
(9) Resigned effective June 29, 2010. Transferred to Alabama Power Company.
(10) Resigned effective August 12, 2010. Transferred to Alabama Power Company.
(11) Elected effective August 13, 2010.
(12) Retired effective August 31, 2010.
(13) Elected effective October 19, 2010.

CORPORATE INFORMATION
Gulf Power Company 2010 Annual Report

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 over 430,000 customers within its service area of approximately 7,500 square miles in the Florida panhandle. In 2010, retail energy sales accounted for 73 percent of the Company's total sales of 15.5 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
BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900
(800) 554-7626
www.bnymellon.com/shareowner/equityaccess

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
The Bank of New York Mellon
Global Corporate Trust
900 Ashwood Parkway, 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:
Gulf Power Company
500 Bayfront Parkway
Pensacola, FL 32520
(850) 444-6111

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

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, GA 30303-1924

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